UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended March 31, 2004 or

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from _______ to _______.

Commission file number: 1-14323

ENTERPRISE PRODUCTS PARTNERS L.P.

(Exact name of Registrant as specified in its charters)

Delaware	**76-0568219**
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)

2727 North Loop West, Houston, Texas	**77008-1044**
(Address of Principal Executive Offices)	(Zip Code)

Registrant's Telephone Number, including area code: **(713) 880-6500**

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

YES [X] NO [ ]

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act).

YES [X] NO [ ]

There were 229,661,604 common units and 4,413,549 Class B special units of *Enterprise Products Partners L.P.* outstanding at May 5, 2003. Enterprise Products Partners L.P.'s Common Units trade on the New York Stock Exchange under symbol "EPD."

ENTERPRISE PRODUCTS PARTNERS L.P.
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Glossary

The following abbreviations, acronyms or terms used in this Form 10-Q are defined below:

Acadian Gas	Acadian Gas, LLC and subsidiaries, acquired from Shell in April 2001
Accum. OCI (or AOCI)	Accumulated Other Comprehensive Income
Administrative Services Agreement	First Amended and Restated Administrative Services Agreement, effective as of January 1, 2004, among EPCO, the Company, the Operating Partnership, the General Partner and the OLP General Partner (formerly, the “EPCO Agreement”)
BBtus	Billion British thermal units, a measure of heating value
Bcf/d	Billion cubic feet per day
BEF	Belvieu Environmental Fuels, a majority owned subsidiary
Belle Rose	Belle Rose NGL Pipeline LLC, an equity method investment
BRF	Baton Rouge Fractionators LLC, an equity method investment
BRPC	Baton Rouge Propylene Concentrator, LLC, an equity method investment
CEO	Chief Executive Officer
CFO	Chief Financial Officer
CMAI	Chemical Market Associates, Inc.
CPG	Cents per gallon
Diamond-Koch	Refers to common affiliates of both Valero Energy Corporation and Koch Industries, Inc.
Dixie	Dixie Pipeline Company, an equity method investment
DRIP	Distribution Reinvestment Plan
El Paso	El Paso Corporation and its affiliates
EPCO	Enterprise Products Company, an affiliate of the Company and our ultimate parent company (including its affiliates)
EPIK	EPIK Terminalling L.P. and EPIK Gas Liquids, LLC, collectively (a former equity method investment that we acquired the remaining ownership interests in March 2003)
EPOLP	Enterprise Products Operating L.P., the operating subsidiary of the Company (also referred to as the "Operating Partnership")
Evangeline	Evangeline Gas Pipeline Company, L.P. and Evangeline Gas Corp., collectively, an equity method investment
FASB	Financial Accounting Standards Board
Feedstock	A raw material required for an industrial process such as in petrochemical manufacturing
Forward sales contracts	The sale of a commodity or other product in a current period for delivery in a future period.
GAAP	Generally Accepted Accounting Principles in the United States of America
General Partner	Enterprise Products GP, LLC, the general partner of the Company
GulfTerra	GulfTerra Energy Partners, L.P.
GulfTerra GP	GulfTerra Energy Company, L.L.C., the general partner of GulfTerra
La Porte	La Porte Pipeline Company, L.P. and La Porte GP, LLC, collectively, an equity method investment
LIBOR	London interbank offered rate
MBA	Mont Belvieu Associates, see “MBA acquisition” below
MBA acquisition	Refers to the acquisition of Mont Belvieu Associates' remaining interest in the Mont Belvieu NGL fractionation facility in 1999
MBFC	Mississippi Business Finance Corporation
MBPD	Thousand barrels per day
Mid-America	Mid-America Pipeline Company, LLC
Mmcf	Million cubic feet
Mont Belvieu	Mont Belvieu, Texas
Moody’s	Moody’s Investors Service
MTBE	Methyl tertiary butyl ether
Nemo	Nemo Gathering Company, LLC, an equity method investment

Neptune	Neptune Pipeline Company, L.L.C., an equity method investment
NGL or NGLs	Natural gas liquid(s)
NYSE	New York Stock Exchange
OPIS	Oil Price Information Service
Operating Partnership	Enterprise Products Operating L.P. and its affiliates
OTC	Olefins Terminal Corporation
Promix	K/D/S Promix LLC, an equity method investment
SEC	U.S. Securities and Exchange Commission
Seminole	Seminole Pipeline Company
SFAS	Statement of Financial Accounting Standards issued by the FASB
Shell	Shell Oil Company, its subsidiaries and affiliates
Splitter III	Refers to the propylene fractionation facility we acquired from Diamond-Koch
Starfish	Starfish Pipeline Company, LLC, an equity method investment
Throughput	Refers to the physical movement of volumes through a pipeline
Tri-States	Tri-States NGL Pipeline LLC, an equity method investment at March 31, 2004. On April 1, 2004, Tri-States became a 66.7% consolidated subsidiary of ours.
VESCO	Venice Energy Services Company, LLC, a cost method investment
Williams	The Williams Companies, Inc. and its affiliates
Wilprise	Wilprise Pipeline Company, LLC
1998 Plan	EPCO’s 1998 Long-Term Incentive Plan
1999 Trust	EPOLP 1999 Grantor Trust, a subsidiary of EPOLP

For definitions of other commonly used terms used in our industry, please refer to the “Glossary” section of our 2003 annual report on Form 10-K (Commission File No. 1-14323).

PART I. ITEM 1. FINANCIAL STATEMENTS.

ENTERPRISE PRODUCTS PARTNERS L.P.
CONDENSED CONSOLIDATED BALANCE SHEETS
(Dollars in thousands)

ASSETS	March 31, 2004	December 31, 2003
Current Assets		
Cash and cash equivalents (includes restricted cash of $8,026 at March 31, 2004 and $13,851 at December 31, 2003)	$ 52,821	$ 44,317
Accounts and notes receivable - trade, net of allowance for doubtful accounts of $20,438 at March 31, 2004 and $20,423 at December 31, 2003	398,831	462,198
Accounts receivable – related parties	9,751	347
Inventories	168,330	150,161
Prepaid and other current assets	55,973	30,160
Total current assets	685,706	687,183
Property, Plant and Equipment, net	2,951,621	2,963,505
Investments in and Advances to Unconsolidated Affiliates	766,293	767,759
Intangible Assets, net of accumulated amortization of $44,193 at March 31, 2004 and $40,371 at December 31, 2003	265,071	268,893
Goodwill	82,427	82,427
Deferred Tax Asset	8,784	10,437
Long-term Receivables	5,282	5,454
Other Assets	17,133	17,156
Total	$ 4,782,317	$ 4,802,814
LIABILITIES AND PARTNERS' EQUITY		
Current Liabilities		
Current maturities of debt	$ 15,000	$ 240,000
Accounts payable – trade	58,507	68,384
Accounts payable – related parties	25,209	38,045
Accrued gas payables	588,340	622,982
Accrued expenses	15,633	24,695
Accrued interest	14,702	45,350
Other current liabilities	50,585	57,420
Total current liabilities	767,976	1,096,876
Long-Term Debt	2,195,876	1,899,548
Other Long-Term Liabilities	9,027	14,081
Minority Interest	88,531	86,356
Partners' Equity		
Common units (214,661,604 units outstanding at March 31, 2004 and 213,366,760 at December 31, 2003)	1,576,633	1,582,951
Class B special units (4,413,549 units outstanding at March 31, 2004 and December 31, 2003)	99,620	100,182
Treasury units, at cost (557,330 units outstanding at March 31, 2004 and 798,313 units at December 31, 2003)	(11,416)	(16,519)
General Partner	34,209	34,349
Accumulated Other Comprehensive Income	21,861	4,990
Total Partners' Equity	1,720,907	1,705,953
Total	$ 4,782,317	$ 4,802,814

See Notes to Unaudited Condensed Consolidated Financial Statements

ENTERPRISE PRODUCTS PARTNERS L.P.
CONDENSED STATEMENTS OF CONSOLIDATED OPERATIONS
AND COMPREHENSIVE INCOME
(Dollars in thousands, except per unit amounts)

	For the Three Months Ended March 31, 2004	For the Three Months Ended March 31, 2003
REVENUES		
Third parties	$ 1,549,587	$ 1,348,782
Related parties	155,303	132,804
Total	1,704,890	1,481,586
COST AND EXPENSES		
Operating costs and expenses		
Third parties	1,405,983	1,152,302
Related parties	215,525	234,402
Total operating costs and expenses	1,621,508	1,386,704
Selling, general and administrative costs		
Third parties	2,572	5,087
Related parties	6,894	6,384
Total selling, general and administrative costs	9,466	11,471
Total	1,630,974	1,398,175
EQUITY IN INCOME OF UNCONSOLIDATED AFFILIATES	13,398	1,621
OPERATING INCOME	87,314	85,032
OTHER INCOME (EXPENSE)		
Interest expense	(32,618)	(41,911)
Dividend income from unconsolidated affiliates	1,250	2,601
Other, net	161	234
Other expense	(31,207)	(39,076)
INCOME BEFORE PROVISION FOR INCOME TAXES, MINORITY INTEREST AND CHANGE IN ACCOUNTING PRINCIPLE	56,107	45,956
PROVISION FOR INCOME TAXES	(1,625)	(3,129)
INCOME BEFORE MINORITY INTEREST AND CHANGE IN ACCOUNTING PRINCIPLE	54,482	42,827
MINORITY INTEREST	(2,954)	(2,322)
INCOME BEFORE CHANGE IN ACCOUNTING PRINCIPLE	51,528	40,505
CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE (see Note 1)	7,013	
NET INCOME	$ 58,541	$ 40,505
Cash flow hedges	16,973	5,354
Reclassification of cash flow hedges	(102)	3,492
COMPREHENSIVE INCOME	$ 75,412	$ 49,351
ALLOCATION OF NET INCOME TO:		
Limited partners' interest in net income	$ 51,219	$ 36,368
General partner interest in net income	$ 7,322	$ 4,137
EARNINGS PER UNIT: (see Note 14)		
Basic income per unit before change in accounting principle and general partner interest	$ 0.24	$ 0.22
Basic net income per unit, net of general partner interest	$ 0.24	$ 0.20
Diluted income per unit before change in accounting principle and general partner interest	$ 0.23	$ 0.21
Diluted net income per unit, net of general partner interest	$ 0.23	$ 0.19

See Notes to Unaudited Condensed Consolidated Financial Statements

ENTERPRISE PRODUCTS PARTNERS L.P.
CONDENSED STATEMENTS OF CONSOLIDATED CASH FLOWS
(Dollars in thousands)

	For the Three Months Ended March 31, 2004	2003
OPERATING ACTIVITIES		
Net income	$ 58,541	$ 40,505
Adjustments to reconcile net income to cash flows provided by (used for) operating activities:		
Depreciation and amortization in operating costs and expenses	30,520	27,657
Depreciation in selling, general and administrative costs	65	22
Amortization in interest expense	798	11,582
Equity in income of unconsolidated affiliates	(13,398)	(1,621)
Distributions received from unconsolidated affiliates	15,682	15,626
Cumulative effect of change in accounting principle	(7,013)	
Operating lease expense paid by EPCO	2,274	2,251
Minority interest	2,954	2,321
Loss on sale of assets	98	4
Deferred income tax expense	1,687	2,733
Changes in fair market value of financial instruments	3	(28)
Decrease (increase) in restricted cash	5,825	(10,006)
Net effect of changes in operating accounts (see Note 11)	(68,431)	50,497
Operating activities cash flows	29,605	141,543
INVESTING ACTIVITIES		
Capital expenditures	(15,003)	(23,835)
Proceeds from sale of assets	10	34
Business combinations, net of cash received		(28,783)
Investments in and advances to unconsolidated affiliates	(818)	(20,509)
Investing activities cash flows	(15,811)	(73,093)
FINANCING ACTIVITIES		
Borrowings under debt agreements	202,000	896,210
Repayments of debt	(137,000)	(1,141,000)
Debt issuance costs	(954)	(6,683)
Distributions paid to partners	(91,258)	(69,155)
Distributions paid to minority interests	(779)	(2,517)
Contributions from minority interests		2,631
Proceeds from issuance of common units	23,142	255,482
Treasury units reissued	5,384	
Settlement of treasury lock financial instruments		5,354
Financing activities cash flows	535	(59,678)
NET CHANGE IN CASH AND CASH EQUIVALENTS	14,329	8,772
CASH AND CASH EQUIVALENTS, JANUARY 1	30,466	13,817
CASH AND CASH EQUIVALENTS, MARCH 31	$ 44,795	$ 22,589

See Notes to Unaudited Condensed Consolidated Financial Statements

ENTERPRISE PRODUCTS PARTNERS L.P.
CONDENSED STATEMENTS OF CONSOLIDATED PARTNERS' EQUITY
(Dollars in thousands, see Note 9 for unit history)

	Limited Partners					
	Common units	**Class B special units**	**Treasury units**	**General Partner**	**Accum. OCI**	**Total**
Balance, January 1, 2004	$1,582,951	$ 100,182	$ (16,519)	$ 34,349	$ 4,990	$1,705,953
Net income	50,187	1,032		7,322		58,541
Operating leases paid by EPCO	2,184	45		45		2,274
Cash distributions to partners	(81,638)	(1,644)		(7,976)		(91,258)
Proceeds from issuance of common units	22,679			463		23,142
Treasury unit transactions:						
- Reissued to satisfy unit options			5,103			5,103
- Gain on reissued treasury units	270	5		6		281
Interest rate hedging financial instruments recorded as cash flow hedges (see Note 12):						
- Increase in fair value					16,973	16,973
- Amortization of 2003 gain as component of interest expense					(102)	(102)
Balance, March 31, 2004	$1,576,633	$ 99,620	$ (11,416)	$ 34,209	$ 21,861	$1,720,907

See Notes to Unaudited Condensed Consolidated Financial Statements

ENTERPRISE PRODUCTS PARTNERS L.P.
NOTES TO UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

1. GENERAL

ENTERPRISE PRODUCTS PARTNERS L.P. including its consolidated subsidiaries is a publicly traded Delaware limited partnership listed on the NYSE under the ticker symbol "EPD." Unless the context requires otherwise, references to "we," "us," "our," "the Company" or "Enterprise" are intended to mean the consolidated business and operations of Enterprise Products Partners L.P. Certain abbreviated entity names and other capitalized and industry terms are defined within the glossary of this quarterly report on Form 10-Q.

We were formed in April 1998 to own and operate certain NGL-related businesses of Enterprise Products Company ("EPCO"). We conduct substantially all of our business through a wholly owned subsidiary, Enterprise Products Operating L.P. (our "Operating Partnership"). We are owned 98% by our limited partners and 2% by Enterprise Products GP, LLC (our "General Partner"). We and our General Partner are affiliates of EPCO.

In the opinion of Enterprise, the accompanying unaudited consolidated financial statements include all adjustments consisting of normal recurring accruals necessary for a fair presentation. Although we believe the disclosures in these financial statements are adequate to make the information presented not misleading, certain information and footnote disclosures normally included in annual financial statements prepared in accordance with GAAP have been condensed or omitted pursuant to the rules and regulations of the SEC. These unaudited financial statements should be read in conjunction with our annual report on Form 10-K (File No. 1-14323) for the year ended December 31, 2003.

Essentially all of our assets, liabilities, revenues and expenses are recorded at the Operating Partnership level in our consolidated financial statements. We act as guarantor of certain of our Operating Partnership's debt obligations. See Note 15 for condensed financial information of our Operating Partnership.

The results of operations for the three month period ended March 31, 2004 are not necessarily indicative of the results to be expected for the full year.

Dollar amounts presented in the tabular data within these footnote disclosures are stated in thousands of dollars, unless otherwise indicated.

Certain reclassifications have been made to the prior year's financial statements to conform to the current year presentation.

CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE represents the effect of changing the method our majority owned BEF subsidiary uses to account for its planned major maintenance activities from the accrue-in-advance method to the expense-as-incurred method. These major maintenance costs, which typically result in facility shutdowns for 30 to 45 days, are principally comprised of amounts paid to third parties for materials, contract services, and other related items.

We have historically used the expense-as-incurred method for planned major maintenance activities. The change in accounting for our majority owned BEF subsidiary conforms the Company's accounting for all planned major maintenance costs and changes the method to better reflect expenses in the period incurred. As such, we believe the change is to a method that is preferable in the circumstances.

The cumulative effect of this accounting change for years prior to 2004, which is shown separately in the Statement of Consolidated Operations and Comprehensive Income for 2004, resulted in a benefit of $7 million. See Note 14 for information regarding the effect of the accounting change on basic and diluted earnings per unit.

For the periods indicated, the following table shows pro forma net income and earnings per unit amounts assuming the accounting change was applied retroactively to January 1, 2003:

	For the Three Months Ended March 31,	
	2004	**2003**
Pro Forma income statement amounts:		
Income before minority interest	$ 54,482	$ 41,846
Net income before general partner interest	$ 53,866	$ 39,534
Limited partner interest in net income	$ 46,637	$ 35,406
Pro forma per unit data (basic):		
Units outstanding (see Note 14)	218,463	186,191
Per unit data:		
Income before minority interest	$ 0.25	$ 0.22
Net income before general partner interest	0.25	0.21
Limited partner interest in net income	$ 0.21	$ 0.19
Pro forma per unit data (diluted):		
Units outstanding (see Note 14)	218,960	196,191
Per unit data:		
Income before minority interest	$ 0.25	$ 0.21
Net income before general partner interest	0.25	0.20
Limited partner interest in net income	$ 0.21	$ 0.18

UNIT OPTION PLAN ACCOUNTING is based on the intrinsic-value method described in APB No. 25, "*Accounting for Stock Issued to Employees*." Under this method, no compensation expense is recorded related to options granted when the exercise price is equal to or greater than the market price of the underlying equity on the date of grant. In accordance with SFAS No. 148, "*Accounting for Stock-Based Compensation – Transition and Disclosure*," we disclose the pro forma effect on our earnings as if the fair-value method of SFAS No. 123, "*Accounting for Stock-Based Compensation*" had been used instead of the intrinsic-value of APB No. 25. The effects of applying SFAS No. 123 in the following pro forma disclosure may not be indicative of future amounts as additional awards in future years are anticipated.

The following table shows the pro forma effects for the periods indicated.

	For the Three Months Ended March 31,	
	2004	**2003**
Historical net income	$ 58,541	$ 40,505
Additional unit option-based compensation expense estimated using fair value-based method	(105)	(277)
Pro forma net income	$ 58,436	$ 40,228
Basic earnings per unit:		
As reported	$ 0.24	$ 0.20
Pro forma	0.23	0.19
Diluted earnings per unit:		
As reported	$ 0.23	$ 0.19
Pro forma	0.23	0.18

2. RECENTLY ISSUED ACCOUNTING STANDARDS

FIN 46, "Consolidation of Variable Interest Entities – An Interpretation of ARB No. 51." This interpretation of ARB No. 51 addresses requirements for accounting consolidation of a variable interest entity ("VIE") with its primary beneficiary. In general, if an equity owner of a VIE meets certain criteria defined within FIN 46, the assets, liabilities and results of the activities of the VIE should be included in the consolidated financial statements of the owner. Our adoption of FIN 46 (as amended by FIN 46R) in 2003 has had no material effect on our consolidated financial statements.

Due to the complexity of FIN 46 (as amended by FIN 46R and interpreted), the FASB is continuing to provide guidance regarding implementation issues. Since this guidance is still continuing, our conclusions regarding the application of this guidance may be altered. As a result, adjustments may be recorded in future periods as we adopt new FASB interpretations of FIN 46.

EITF 03-16, "Accounting for Investments in Limited Liability Companies." This accounting guidance requires that investments in limited liability companies (or "LLCs") that have separate ownership accounts for each investor be accounted for similar to a limited partnership investment under SOP No. 78-9, "*Accounting for Investments in Real Estate Ventures*." Under this new guidance (applicable for the period beginning July 1, 2004), investors would be required to apply the equity method of accounting to their investments at a much lower ownership threshold (typically any ownership interest greater than 3-5%) than the 20% threshold applied under APB Opinion No. 18, "*The Equity Method of Accounting for Investments in Common Stock*."

Currently, we account for our 13.1% investment in Venice Energy Services Company, LLC ("VESCO") using the cost method. As a result, we have recognized dividend income from VESCO to the extent that we have received cash distributions from them. In accordance with the new accounting guidance in EITF 03-16, we will record a retroactive cumulative effect adjustment equal to the difference between (i) equity earnings from VESCO that would have been recorded using the equity method in prior periods and (ii) the dividend income from VESCO that was recorded using the cost method. We are currently studying the effect that EITF 03-16 will have on our investment in VESCO; however, based on information available, we do not believe that the implementation of this new accounting guidance will have a material effect on our financial statements.

3. BUSINESS COMBINATIONS

We did not enter into any business acquisitions during the first quarter of 2004; however, we are still expecting completion of the proposed merger with GulfTerra during the second half of 2004. In general, the proposed merger with GulfTerra involves the following three steps:

- *Step One*. On December 15, 2003, we purchased a 50% membership interest in GulfTerra's general partner ("GulfTerra GP") for $425 million. GulfTerra's general partner owns a 1% general partner interest in GulfTerra. This investment is accounted for using the equity method and is already recorded in our historical balance sheet at December 31, 2003. See Note 6 regarding preliminary estimates of the purchase price allocation for GulfTerra GP. This transaction is referred to as Step One of the proposed merger and will remain in effect even if the remainder of the proposed merger and post-merger transactions, which are referred to as Step Two and Step Three, do not occur.

- *Step Two*. If all necessary regulatory and unitholder approvals are received and the other merger agreement conditions are either fulfilled or waived and the following steps are consummated, we will own 100% of the limited and general partner interests in GulfTerra. At that time, the proposed merger will be accounted for using the purchase method, and GulfTerra will be a consolidated subsidiary of Enterprise. Step Two of the proposed merger includes the following transactions:

    - El Paso's exchange of its remaining 50% membership interest in GulfTerra GP for a cash payment by our General Partner of $370 million (which will not be funded or reimbursed by us) and a 9.9% membership in our General Partner, and the subsequent capital contribution by our General Partner of such 50% membership interest in GulfTerra GP to us (without increasing our General Partner's interest in our earnings or cash distributions).

    - Our purchase of 10,937,500 GulfTerra Series C units and 2,876,620 GulfTerra common units owned by El Paso for $500 million.

    - The exchange of each remaining GulfTerra common unit for 1.81 Enterprise common units, resulting in the issuance of approximately 104.6 million of our common units to GulfTerra unitholders.

- *Step Three*. Immediately after Step Two is completed, we expect to acquire certain South Texas midstream energy assets from El Paso for $150 million plus the value of then existing inventories related to such assets.

We anticipate that our obligations under Steps Two and Three of the proposed merger to pay El Paso $650 million will be financed initially with a short-term acquisition term loan and with borrowings under our revolving credit facilities.

Our preliminary estimate of the total consideration for Steps One, Two and Three we would pay or issue is approximately $4.0 billion. For a period of three years following the closing of the proposed merger, at our request El Paso will provide certain support services to GulfTerra similar to those provided by El Paso prior to the closing of the merger. GulfTerra will reimburse El Paso for 110% of its direct costs for such services (excluding any overhead costs). El Paso will make transition support payments to us in annual amounts of $18 million, $15 million and $12 million for the first, second and third years of such period, respectively, payable in twelve equal monthly installments for each such year. These transition support payments are included in our preliminary estimate of total consideration.

A number of conditions must be satisfied before we can complete the merger, including approval by the unitholders of both Enterprise and GulfTerra and the expiration or termination of applicable waiting periods under the Hart-Scott-Rodino Antitrust Improvements Act of 1974. While we cannot predict if and when all of the conditions of the proposed merger will be satisfied, we expect to complete the transaction in the second half of 2004.

To review a copy of the merger agreement and related transaction documents, please read our Current Reports on Form 8-K filed with the SEC on December 15, 2003 and April 21, 2004.

4. INVENTORIES

Our inventories were as follows at the dates indicated:

	March 31, 2004	December 31, 2003
Working inventory	$ 164,072	$ 135,451
Forward-sales inventory	4,258	14,710
Inventory	$ 168,330	$ 150,161

Our regular trade (or "working") inventory is comprised of inventories of natural gas, NGLs and petrochemical products that are available for sale or used in the provision of services. The forward sales inventory is comprised of segregated NGL volumes dedicated to the fulfillment of forward sales contracts. Both inventories are valued at the lower of average cost or market.

Due to fluctuating conditions in the NGL, natural gas and petrochemical industry, we occasionally recognize lower of average cost or market ("LCM") adjustments when the cost of our inventories exceed their net realizable value. These non-cash adjustments are charged to operating costs and expenses in the period they are recognized. For the three months ended March 31, 2004 and 2003, we recognized $4.2 million and $10.4 million, respectively, of LCM adjustments.

5. PROPERTY, PLANT AND EQUIPMENT

Our property, plant and equipment and accumulated depreciation were as follows at the dates indicated:

	Estimated Useful Life in Years	March 31, 2004	December 31, 2003
Plants and pipelines (1)	5-35 (4)	$ 3,258,067	$ 3,214,463
Underground and other storage facilities (2)	5-35 (5)	292,263	288,199
Transportation equipment (3)	3-10	6,231	5,676
Land		23,447	23,447
Construction in progress		40,835	74,431
Total		3,620,843	3,606,216
Less accumulated depreciation		669,222	642,711
Property, plant and equipment, net		$ 2,951,621	$ 2,963,505

(1) Plants and pipelines include processing plants; NGL, petrochemical and natural gas pipelines; terminal loading and unloading facilities; office furniture and equipment; buildings; laboratory and shop equipment; and related assets.
(2) Underground and other storage facilities includes underground product storage caverns; storage tanks; water wells; and related assets.
(3) Transportation equipment includes vehicles and similar assets used in our operations.
(4) In general, the estimated useful lives of major components of this category are: processing plants, 20-35 years; pipelines, 3-35 years (with some equipment at 5 years); terminal facilities, 10-35 years; office furniture and equipment, 3-20 years; buildings, 20-35 years; and laboratory and shop equipment, 5-35 years.
(5) In general, the estimated useful lives of major components of this category are: underground storage wells, 30-35 years (with some components at 5 years); storage tanks, 10-35 years; and water wells, 25-35 years (with some components at 5 years).

Depreciation expense for the three months ended March 31, 2004 and 2003 was $26.8 million and $24.1 million, respectively.

6. INVESTMENTS IN AND ADVANCES TO UNCONSOLIDATED AFFILIATES

We own interests in a number of related businesses that are accounted for using the equity or cost methods. The investments in and advances to these unconsolidated affiliates are grouped according to the business segment to which they relate. For a general discussion of business segments, see Note 13. The following table shows our investments in and advances to unconsolidated affiliates at the dates indicated:

	Ownership Percentage at March 31, 2004	March 31, 2004	December 31, 2003
Accounted for using the equity method:			
Pipeline:			
GulfTerra GP	50.0%	$ 425,082	$ 424,947
Neptune	25.7%	73,539	74,647
Tri-States	50.0%	43,401	44,119
Starfish	50.0%	40,287	40,664
Dixie	19.9%	36,066	35,988
Nemo	33.9%	12,691	12,294
Belle Rose	41.7%	10,511	10,780
Evangeline	49.5%	2,675	2,519
Fractionation:			
Promix	33.3%	39,772	38,903
BRF	32.3%	27,459	27,892
BRPC	30.0%	16,657	16,584
La Porte	50.0%	5,153	5,422
Accounted for using the cost method:			
Processing:			
VESCO	13.1%	33,000	33,000
Total		$ 766,293	$ 767,759

Our initial investment in Promix, La Porte, Dixie, Tri-States, Neptune, Nemo and GulfTerra GP exceeded our share of the historical cost of the underlying net assets of such entities ("excess cost"). The excess cost amounts are reflected in our investments in and advances to unconsolidated affiliates for these entities. That portion of excess cost attributable to tangible or amortizable intangible assets of each entity is amortized over the estimated useful of the underlying asset(s) as a reduction in equity earnings from the investee. That portion of excess cost attributable to goodwill or non-amortizable intangible assets is not amortized. Equity method investments, including their associated excess cost amounts, are evaluated for impairment whenever events or changes in circumstances indicate that there is a loss in value of the investment which is an other than temporary decline. The following table summarizes our excess cost information at March 31, 2004 and December 31, 2003 by the business segment to which the unconsolidated affiliates relate:

		Initial Excess Cost attributable to		Unamortized balance at	
	Amort. Periods	Tangible assets	Goodwill (1)	March 31, 2004	December 31, 2003
Fractionation	20-35 years	$ 8,828		$ 6,676	$ 7,045
Pipelines (2)	35 years	45,698	$ 337,460	378,085	378,241

(1) Excess cost attributable to goodwill is not amortized; however, our investments in unconsolidated affiliates (which include excess cost amounts) are tested for impairment whenever events or circumstances indicate that there is a loss in value of the investment which is an other than temporary decline.

(2) This category includes our preliminary allocation of GulfTerra GP's $328.2 million of excess cost to goodwill.

The Pipelines section in the preceding table includes $337.5 million of excess cost attributable to goodwill, of which $328.2 million results from our December 2003 purchase of a 50% membership interest in GulfTerra GP. The allocation of the $328.2 million of excess cost to goodwill (which represents potential intangible assets, excess of fair values over carrying values of tangible assets and remaining goodwill, if any) is preliminary pending completion of a fair value analysis which is expected to be completed during the last half of 2004. The table below shows the potential decrease in equity earnings from GulfTerra GP if certain amounts included in this excess cost were ultimately assigned to tangible or amortizable intangible assets. For purposes of calculating this sensitivity, we have applied the straight-line method of cost allocation over an estimated useful life of 20-years to various fair values.

Amount allocated to Tangible or Amortizable Assets out of GulfTerra GP Excess Cost Goodwill	Excess Cost attributed to tangible or intangible assets	Estimated Annual Reduction in Equity Earnings from GulfTerra GP
20% of excess cost or $65.6 million	$ 65,643	$ 3,282
40% of excess cost or $131.3 million	131,286	6,564
60% of excess cost or $196.9 million	196,928	9,846
80% of excess cost or $262.6 million	262,571	13,129
100% of excess cost or $328.2 million	328,214	16,411

The following table shows our equity in income (loss) of unconsolidated affiliates for the periods indicated:

	For the Three Months Ended March 31, 2004	2003
Pipelines:		
GulfTerra GP (1)	$ 10,554	
Neptune	(516)	$ 10
Tri-States	25	549
Starfish	1,058	1,149
Dixie	741	801
Nemo	441	336
Belle Rose	(108)	(29)
Evangeline	24	(19)
EPIK (2)		1,818
Wilprise (2)		163
Fractionation:		
Promix	374	260
BRF	410	142
BRPC	545	148
La Porte	(150)	(181)
OTC (2)		(85)
Octane Enhancement:		
BEF (2)		(3,441)
Total	$ 13,398	$ 1,621

(1) In December 2003, we acquired a 50% membership interest in the general partner of GulfTerra Energy Partners, L.P. from El Paso.

(2) We acquired additional ownership interests in or control over these entities during 2003 resulting in our consolidation of each company's post-acquisition financial results with those of our own. Our consolidation of each company's post-acquisition financial results began in the following periods: EPIK, March 2003; Wilprise, October 2003; OTC, August 2003; and BEF, September 2003.

The following table presents summarized income statement information for our unconsolidated affiliates accounted for using the equity method (for the periods indicated, on a 100% basis).

	Summarized Income Statement Information for the Three Months Ended					
	March 31, 2004			March 31, 2003		
	Revenues	Operating Income	Net Income	Revenues	Operating Income (Loss)	Net Income (Loss)
Pipelines (1)	$ 79,474	$ 11,277	$ 6,758	$ 91,974	$ 20,927	$ 14,661
Fractionation	18,553	4,228	4,223	18,114	1,524	1,505
Octane Enhancement (2)	n/a	n/a	n/a	45,651	(10,356)	(10,322)

(1) The 2003 period includes EPIK and Wilprise, which became consolidated subsidiaries during March 2003 and October 2003, respectively. As a result, revenues, operating income and net income from these assets are not included in the 2004 amounts for this category.

(2) Octane Enhancement represents our investment in a facility owned by BEF that produces motor gasoline additives to enhance octane. We increased our ownership interest in this facility from 33.3% to 66.7% on September 30, 2003. As a result, we began consolidating BEF's financial results with those of our own beginning with the fourth quarter of 2003 (BEF was an equity method investment prior to September 30, 2003).

Expected change in accounting method for VESCO

As a result of newly issued accounting guidance per EITF 03-16, we expect to change our method of accounting for VESCO from the cost method to the equity method on July 1, 2004. The VESCO investment consists of a 13.1% membership interest in a limited liability company that owns a natural gas processing plant, NGL fractionation facilities, storage assets and gas gathering pipelines located in south Louisiana.

7. INTANGIBLE ASSETS AND GOODWILL

Intangible assets

The following table summarizes our amortizable intangible assets at the dates indicated:

		At March 31, 2004		At December 31, 2003	
	Gross Value	Accum. Amort.	Carrying Value	Accum. Amort.	Carrying Value
Shell natural gas processing agreement	$ 206,216	$ (36,824)	$ 169,392	$ (34,063)	$ 172,153
Mont Belvieu Storage II contracts	8,127	(523)	7,604	(464)	7,663
Mont Belvieu Splitter III contracts	53,000	(3,281)	49,719	(2,902)	50,098
Toca-Western natural gas processing contracts	11,187	(1,025)	10,162	(885)	10,302
Toca-Western NGL fractionation contracts	20,042	(1,838)	18,204	(1,587)	18,455
Venice contracts	6,635	(251)	6,384	(136)	6,499
Port Neches pipeline contracts	2,400	(403)	1,997	(310)	2,090
BEF UOP License Fee	1,657	(48)	1,609	(24)	1,633
Total	$ 309,264	$ (44,193)	$ 265,071	$ (40,371)	$ 268,893

All of the intangible assets noted in the preceding table are subject to amortization. Amortization expense for the three months ended March 31, 2004 and 2003 was $3.8 million and $3.6 million, respectively. For the remainder of 2004, amortization expense attributable to these intangible assets is currently estimated at $11.5 million.

Goodwill

The following table summarizes our goodwill amounts at March 31, 2004 and December 31, 2003 (excluding amounts included in the carrying value of unconsolidated affiliates – See Note 6).

	Segment Affiliation	Goodwill Balance
Splitter III acquisition (1)	Fractionation	$ 73,690
MBA acquisition (2)	Fractionation	7,857
Wilprise acquisition (3)	Pipelines	880
		$ 82,427

(1) Amount recorded in connection with our acquisition of propylene fractionation assets from Diamond-Koch in February 2002.
(2) Amount recorded in connection with our acquisition of an additional interest in Mont Belvieu Associates in July 2001, which owned an interest in our Mont Belvieu NGL fractionation facility.
(3) Amount recorded in connection with our acquisition of an additional 37.4% in Wilprise in October 2003.

8. RELATED PARTY TRANSACTIONS

Relationship with EPCO

We have an extensive and ongoing relationship with EPCO. EPCO is controlled by Dan L. Duncan, who is also a director (and Chairman of the Board of Directors) of our General Partner. In addition, the remaining executive and other officers of our General Partner are employees of EPCO, including O.S. Andras who is President and Chief Executive Officer and a director of the General Partner. The principal business activity of the General Partner is to act as our managing partner. Collectively, EPCO and its affiliates owned 56.6% of Enterprise at March 31, 2004, which includes the 2% ownership interest of our General Partner (of which EPCO and its affiliates own 100%).

We have no employees. All of our management, administrative and operating functions are performed by employees of EPCO pursuant to the Administrative Services Agreement. Prior to January 1, 2004, we reimbursed EPCO for the costs of its employees who performed operating functions for us and for costs related to certain of its management and administrative personnel hired in response to the expansion of our business. In addition, we paid EPCO a monthly fee for services provided by its other management and administrative employees. On January 1, 2004, the Administrative Services Agreement was amended to eliminate the fee portion of this reimbursement and to provide that we reimburse EPCO for all costs related to management or administrative support for us.

We also have entered into an agreement with EPCO to provide trucking services to us for the transportation of NGLs and other products. In addition, we also buy from and sell to EPCO's Canadian affiliate certain NGL products.

Relationship with Shell

We have a significant commercial relationship with Shell as a partner, customer and vendor. At March 31, 2004, Shell owned an approximate 18.3% equity interest in Enterprise. Shell is our largest customer. Our revenues from Shell primarily reflect the sale of NGL and petrochemical products to Shell and the fees we charge Shell for natural gas processing, pipeline transportation and NGL fractionation services. Our operating costs and expenses with Shell primarily reflect the payment of energy-related expenses related to the Shell natural gas processing agreement and the purchase of NGL products from Shell.

Relationship with unconsolidated affiliates

Our significant related party transactions with unconsolidated affiliates consist of the sale of natural gas to Evangeline, purchase of pipeline transportation services from Dixie and purchase of NGL storage, transportation and fractionation services from Promix. In addition, we sell natural gas to Promix.

The following table summarizes our related party revenues, operating costs and expenses, and selling, general and administrative costs for the periods indicated:

	For the Three Months Ended March 31,	
	2004	**2003**
Revenues		
EPCO and affiliates	$ 2,143	$ 563
Shell and affiliates	104,100	82,220
Unconsolidated affiliates	49,060	50,021
Operating costs and expenses		
EPCO and affiliates	39,113	46,205
Shell and affiliates	166,830	171,714
Unconsolidated affiliates	9,582	16,483
Selling, general and administrative costs		
EPCO and affiliates	6,894	6,384

9. CAPITAL STRUCTURE

Our common and Class B special units represent limited partner interests, which give the holders thereof the right to participate in distributions and to exercise the other rights or privileges available to them under our *Third Amended and Restated Agreement of Limited Partnership* (together with all amendments thereto, the "Partnership Agreement"). Our common units trade on the NYSE under the ticker symbol "EPD." We are managed by our General Partner.

Our partnership agreement generally authorizes us to issue an unlimited number of additional limited partner interests and other equity securities for such consideration and on such terms and conditions as may be established by the General Partner in its sole discretion (subject, under certain circumstances, to the approval of our unitholders). In February 2004, we issued 1,053,861 common units primarily in connection with our distribution reinvestment plan ("DRIP") for which we received net proceeds of approximately $23.1 million, including our General Partner's proportionate net capital contribution of $0.5 million. We used the proceeds from the February 2004 DRIP offering for general partnership purposes. See Note 16 for information regarding our May 2004 equity offering of 15,000,000 common units. During the first quarter of 2004, we reissued 240,983 treasury units at a cost of $5.1 million primarily due to obligations under EPCO employee unit option agreements and recorded a $0.3 million gain on the transactions.

Unit History

The following table details the outstanding balance of each class of units for the periods and at the dates indicated:

	Limited Partners		
	Common Units	**Class B Special Units**	**Treasury Units**
Balance, January 1, 2004	213,366,760	4,413,549	798,313
Common units issued in February 2004	1,053,861		
Treasury units reissued	240,983		(240,983)
Balance, March 31, 2004	214,661,604	4,413,549	557,330

10. DEBT OBLIGATIONS

Our debt consisted of the following at the dates indicated:

	March 31, 2004	December 31, 2003
Borrowings under:		
Interim Term Loan, variable rate, repaid in May 2004 (1)	$ 225,000	$ 225,000
364-Day Revolving Credit Facility, variable rate, due October 2004, $230 million borrowing capacity	90,000	70,000
Multi-Year Revolving Credit Facility, variable rate, due November 2005, $270 million borrowing capacity (2)	160,000	115,000
Senior Notes A, 8.25% fixed rate, due March 2005	350,000	350,000
Seminole Notes, 6.67% fixed rate, $15 million due in December 2004 and 2005 (3)	30,000	30,000
MBFC Loan, 8.70% fixed rate, due March 2010	54,000	54,000
Senior Notes B, 7.50% fixed rate, due February 2011	450,000	450,000
Senior Notes C, 6.375% fixed rate, due February 2013	350,000	350,000
Senior Notes D, 6.875% fixed rate, due March 2033	500,000	500,000
Total principal amount	2,209,000	2,144,000
Unamortized balance of increase in fair value related to hedging a portion of fixed-rate debt (see Note 12)	7,828	1,531
Less unamortized discount on Senior Notes A, B, and D	(5,952)	(5,983)
Subtotal long-term debt	2,210,876	2,139,548
Less current maturities of debt (4)	(15,000)	(240,000)
Long-term debt (4)	$ 2,195,876	$ 1,899,548
Standby letters of credit outstanding, $75 million of credit capacity available under our Multi-Year Revolving Credit Facility	$ 1,300	$ 1,300

(1) We used the proceeds from our May 2004 common unit offering to fully repay the Interim Term Loan (see Note 16).

(2) This revolving credit facility has $270 million of total borrowing capacity, which is reduced by the amount of standby letters of credit outstanding.

(3) Solely as to the assets of our subsidiary, Seminole Pipeline Company, our $2.2 billion in senior indebtedness at March 31, 2004 is structurally subordinated and ranks junior in right of payment to the $30 million of indebtedness of Seminole Pipeline Company.

(4) In accordance with SFAS No. 6, "Classification of Short-Term Obligations Expected to Be Refinanced," long-term and current maturities of debt at March 31, 2004 reflect the classification of such debt obligations at May 5, 2004. With respect to our 364-Day Revolving Credit Facility, borrowings under this facility are not included in current maturities because we have the option and ability to convert any revolving credit balance outstanding at maturity to a one-year term loan (due October 2005) in accordance with the terms of the agreement. With respect to our Interim Term Loan, we reclassified this amount to long-term debt at March 31, 2004 since we used the proceeds from our May 2004 equity offering (see Note 16) to repay this obligation.

Scheduled future maturities of long-term debt. We have long and short-term payment obligations under credit agreements such as our Senior Notes and revolving credit facilities. Scheduled future maturities of debt at March 31, 2004 were: $240 million due in 2004; $615 million due in 2005; $54 million due in 2010; $450 million due in 2011; $350 million due in 2013; and $500 million due in 2033. On May 5, 2004, we used $307 million in net proceeds from our May 2004 equity offering to repay the $225 million Interim Term Loan and approximately $80 million to temporarily reduce debt outstanding under our revolving credit facilities.

Parent-Subsidiary guarantor relationships. We act as guarantor of the debt obligations of our Operating Partnership, with the exception of the Seminole Notes. If the Operating Partnership were to default on any debt we guarantee, we would be responsible for full repayment of that obligation. The Seminole Notes are unsecured obligations of Seminole Pipeline Company (of which we own an effective 78.4% of its capital stock).

Covenants. We were in compliance with the various covenants of our debt agreements at March 31, 2004 and December 31, 2003.

Information regarding variable interest rates paid

The following table shows the range of interest rates paid and weighted-average interest rate paid on our variable rate debt obligations for the three months ended March 31, 2004:

	Range of interest rates paid	**Weighted-average interest rate paid**
364-Day Revolving Credit Facility	1.17% - 4.00%	1.82%
Multi-Year Revolving Credit Facility	1.67% - 4.00%	1.71%
Interim Term Loan	1.72% - 1.78%	1.76%

11. SUPPLEMENTAL CASH FLOWS DISCLOSURE

The net effect of changes in operating assets and liabilities is as follows for the periods indicated:

	For the Three Months Ended March 31,	
	2004	**2003**
Decrease (increase) in:		
Accounts and notes receivable	$ 53,964	$ (83,955)
Inventories	(18,169)	76,079
Prepaid and other current assets	(2,294)	15,238
Other assets	(53)	(503)
Increase (decrease) in:		
Accounts payable	(22,713)	1,471
Accrued gas payable	(34,642)	85,942
Accrued expenses	(9,062)	(16,894)
Accrued interest	(30,648)	(12,364)
Other current liabilities	(4,669)	(14,517)
Other liabilities	(145)	
Net effect of changes in operating accounts	$ (68,431)	$ 50,497

Cash and cash equivalents (as shown on our Statements of Consolidated Cash Flows) excludes restricted cash amounts held by a brokerage firm as margin deposits associated with our financial instruments portfolio and for the physical purchase of natural gas made on the NYMEX exchange. The restricted cash balance at March 31, 2004 and December 31, 2003 was $8.0 million and $13.9 million, respectively.

We recorded certain fair value amounts related to our interest rate hedging financial instruments during the first quarter of 2004 that affected various balance sheet accounts. For information regarding our financial instruments, see Note 12.

12. FINANCIAL INSTRUMENTS

We are exposed to financial market risks, including changes in commodity prices and interest rates. We may use financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to mitigate the risks of certain identifiable and anticipated transactions. In general, the type of risks we attempt to hedge are those related to the variability of future earnings and cash flows caused by changes in commodity prices and interest rates. As a matter of policy, we do not use financial instruments for speculative (or "trading") purposes.

We recognize our financial instruments on the balance sheet as assets and liabilities based on the instrument's fair value. Fair value is generally defined as the amount at which the financial instrument could be exchanged in a current transaction between willing parties, not in a forced or liquidation sale. The estimated fair values of our financial instruments have been determined using available market information and appropriate valuation techniques. We must use considerable judgment, however, in interpreting market data and developing these estimates. Accordingly, our fair value estimates are not necessarily indicative of the amounts that we could realize upon disposition of these instruments. The use of different market assumptions and/or estimation techniques could have a material effect on our estimates of fair value.

Changes in the fair value of financial instrument contracts are recognized currently in earnings unless specific hedge accounting criteria are met. If the financial instruments meet those criteria, the instrument's gains and losses offset the related results of the hedged item in the Statement of Operations and Comprehensive Income for a fair value hedge and are deferred in other comprehensive income for a cash flow hedge. Gains and losses on a cash flow hedge are reclassified into eamings when the forecasted transaction affects earnings. A contract designated as a hedge of an anticipated transaction that is no longer likely to occur is immediately recognized in earnings.

To qualify as a hedge, the item to be hedged must expose us to price risk, interest rate risk or changes in fair value and the hedging instrument must reduce the exposure and meet the hedging requirements of SFAS No. 133, "*Accounting for Derivative Instruments and Hedging Activities*" (as amended and interpreted). We must formally designate the financial instrument as a hedge and document and assess the effectiveness of the hedge at inception and on a quarterly basis. Any ineffectiveness is recorded into earnings immediately.

Due to the complexity of SFAS No. 133 (as amended and interpreted), the FASB is continuing to provide guidance about implementation issues. Since this guidance is still continuing, our conclusions regarding the application of guidance may be altered. As a result, adjustments may be recorded in future periods as we adopt new FASB interpretations of this guidance.

Interest rate risk hedging program

Our interest rate exposure results from variable and fixed rate borrowings under debt agreements (see Note 10). We assess the cash flow risk related to interest rates by identifying and measuring changes in our interest rate exposures that may impact future cash flows and evaluating hedging opportunities to manage these risks. We use analytical techniques to measure our exposure to fluctuations in interest rates, including cash flow sensitivity analysis to estimate the expected impact of changes in interest rates on our future cash flows. The General Partner oversees the strategies associated with these financial risks and approves instruments that are appropriate for our requirements.

We manage a portion of our interest rate risks by utilizing interest rate swaps and similar arrangements. The objective of entering into this type of arrangement is to manage debt service costs by converting a portion of fixed rate debt into variable rate debt or a portion of variable rate debt into fixed rate debt. In general, an interest rate swap requires one party to pay a fixed interest rate on a defined (or "notional") amount while the other party pays a variable rate based on the same notional amount. The notional amount specified in an interest rate swap agreement does not represent exposure to credit loss. We monitor our positions and the credit ratings of counterparties. Management believes the risk of incurring a credit loss on these financial instruments is remote, and that if incurred, such losses would be minimal. We believe that it is prudent to maintain an appropriate balance of variable rate and fixed rate debt.

Fair value hedges – Interest rate swaps. On January 8, 2004, we entered into three interest rate swap agreements under which we exchanged the payment of fixed rate interest on a portion of principal outstanding under Senior Notes B and C for variable rate interest:

Hedged Fixed Rate Debt	Period Covered by Swap	Termination Date of Swap	Fixed to Variable Rate	Notional Amount
Senior Notes B, 7.50% fixed rate, due Feb. 2011	Jan. 2004 to Feb. 2011	Feb. 2011	7.50% to 4.6%	$50 million
Senior Notes C, 6.375% fixed rate, due Feb. 2013	Jan. 2004 to Feb. 2013	Feb. 2013	6.375% to 3.1%	$100 million
Senior Notes C, 6.375% fixed rate, due Feb. 2013	Jan. 2004 to Feb. 2013	Feb. 2013	6.375% to 3.1%	$100 million

We have designated these interest rate swaps as fair value hedges under SFAS No. 133 since they mitigate changes in the fair value of the underlying fixed rate debt. These agreements have a combined notional amount of $250 million and match the maturity dates of the underlying debt being hedged. Under the swap agreements, we pay the counterparty a variable rate based on LIBOR (plus an applicable margin) and receive back from the counterparty a fixed rate payment equal to the stated interest rate of the debt being hedged, based on the notional amounts for each swap agreement. We settle amounts receivable from or payable to the counterparties every six months (the "settlement period").

As effective fair value hedges, an increase in the fair value of these interest rate swaps is equally offset by a increase in fair value of the underlying hedged debt. The offsetting changes in fair value have no effect on current period interest expense. However, the interest rate swaps effectively converted a portion of the underlying fixed rate debt (i.e., the notional amounts hedged for Senior Notes B and C) into variable rate debt. As a result, interest expense will vary depending on the variable rates payable by us under terms of the swap agreements at the end of each settlement period. To the extent that the variable rate amount payable by us at the end of each settlement period is less than the fixed rate amount receivable from the counterparty, we will amortize the difference ratably to earnings as a reduction in interest expense over the settlement period. If the variable rate payable by us at the end of each settlement period is more than the fixed rate amount receivable from the counterparty, we would amortize this difference ratably to earnings as an increase in interest expense over the settlement period.

Total fair value of the interest rate swaps at March 31, 2004 was approximately $6.4 million with an offsetting increase in fair value of the underlying debt. Interest expense in our Statement of Consolidated Operations and Comprehensive Income for the three months ended March 31, 2004 reflects a $1.7 million benefit from these swaps.

Cash flow hedges – Forward starting interest rate swaps. On March 17, 2004, we entered into four forward starting interest rate swap transactions with original maturities of September 30, 2004. A forward starting swap is an agreement that effectively hedges the price on a specific U.S. treasury security for an established period of time. The purpose of these transactions was to effectively hedge the underlying U.S. treasury interest rate associated with our anticipated issuance of debt to refinance the existing debt of GulfTerra after the proposed merger is completed (see Note 3). The forward starting interest rate swaps have been designated as cash flow hedges under SFAS No. 133. The notional amount of the anticipated debt issuances was $2 billion.

On April 23, 2004, we elected to terminate these financial instruments in order to monetize the then current value of the swaps and to reduce future debt service costs. As a result, we received $104.5 million in cash from the counterparties. This amount will be amortized over the life of the anticipated debt (when issued) as a reduction to interest expense. The following table shows the portfolio of forward starting swaps categorized by the term of the underlying anticipated debt offering:

Term of Anticipated Debt Offering (or forecasted transaction)	Notional Amount of Anticipated Debt covered by Forward Starting Swaps	Cash Received upon Settlement of Forward Starting Swaps in April 2004
Five year debt instrument	$ 500.0	$ 18.7
Ten year debt instrument	500.0	26.1
Fifteen year debt instrument	500.0	29.4
Thirty year debt instrument	500.0	30.3
Total	$ 2,000.0	$ 104.5

The non-cash fair value of the forward starting interest rate swaps at March 31, 2004 was $17.0 million and was recorded as a component of AOCI in our Statement of Consolidated Partners' Equity and as an addition to comprehensive income in our Statement of Consolidated Operations and Comprehensive Income for the three months ended March 31, 2004. When the $104.5 million cash settlement is recorded during the second quarter of 2004, it will replace the $17.0 non-cash fair value amount in AOCI and comprehensive income.

Commodity risk hedging program

The prices of natural gas, NGLs, petrochemical products and MTBE are subject to fluctuations in response to changes in supply, market uncertainty and a variety of additional factors that are beyond our control. In order to manage the risks associated with our Processing segment activities, we may enter into various commodity financial instruments. The primary purpose of these risk management activities is to hedge our exposure to price risks associated with natural gas, NGL production and inventories, firm commitments and certain anticipated transactions. The commodity financial instruments we utilize may be settled in cash or with another financial instrument.

We do not hedge our exposure related to MTBE price risks. In addition, we generally do not hedge risks associated with the petrochemical marketing activities that are part of our Fractionation segment. In our Pipelines segment, we utilize a limited number of commodity financial instruments to manage the price Acadian Gas charges or pays certain of its customers for natural gas. Lastly, we do not employ commodity financial instruments in our fee-based marketing business classified under the Other segment.

We have adopted a policy to govern our use of commodity financial instruments to manage the risks of our natural gas and NGL businesses. The objective of this policy is to assist us in achieving our profitability goals while maintaining a portfolio with an acceptable level of risk, defined as remaining within the position limits established by the General Partner. We enter into risk management transactions to manage price risk, basis risk, physical risk or other risks related to our commodity positions on both a short-term (less than 30 days) and long-term basis, not to exceed 24 months. The General Partner oversees our strategies associated with physical and financial risks (such as those mentioned previously), approves specific activities subject to the policy (including authorized products, instruments and markets) and establishes specific guidelines and procedures for implementing and ensuring compliance with the policy.

Our commodity financial instruments may not qualify for hedge accounting treatment under the specific guidelines of SFAS No. 133 (as amended and interpreted). In those situations where the financial instrument does not qualify for hedge accounting treatment, the instrument is accounted for using mark-to-market accounting, which results in a degree of non-cash earnings volatility that is dependent upon changes in the commodity prices underlying these financial instruments. Even though these financial instruments may not qualify for hedge accounting treatment under SFAS No. 133, we view such contracts as hedges since this was the intent when we entered into such positions. Upon entering into such positions, our expectation is that the economic performance of these instruments will mitigate (or offset) the commodity risk being addressed. The specific accounting for these contracts; however, is consistent with the requirements of SFAS No. 133.

The fair value of our commodity financial instrument portfolio at March 31, 2004 and December 31, 2003 and the results of our commodity hedging activities for the three months ended March 31, 2004 and 2003 were both nominal amounts. During both the first quarter of 2004 and the first quarter of 2003, we utilized a limited number of commodity financial instruments.

13. SEGMENT INFORMATION

Operating segments are components of a business about which separate financial information is available. These components are regularly evaluated by the chief operating decision maker in deciding how to allocate resources and in assessing performance. Generally, financial information is required to be reported on the basis that it is used internally for evaluating segment performance and deciding how to allocate resources to segments.

We have five reportable business (or operating) segments: Pipelines, Fractionation, Processing, Octane Enhancement and Other. Our reportable segments are generally organized according to the type of services rendered (or process employed) and products produced and/or sold, as applicable. The segments are regularly evaluated by the CEO of the General Partner. Pipelines consists of NGL, petrochemical and natural gas pipeline systems, storage and import/export terminal services. Fractionation primarily includes NGL fractionation, isomerization, and propylene fractionation services. Processing includes the natural gas processing business and its related NGL marketing activities. Octane Enhancement represents our investment in a facility that produces motor gasoline additives to enhance octane (currently producing MTBE and isobutylene). The Other business segment consists of fee-based marketing services and various operational support activities.

We evaluate segment performance based on the non-GAAP financial measure of gross operating margin. Gross operating margin (either in total or by individual segment) is an important performance measure of the core profitability of our operations. This measure forms the basis of our internal financial reporting and is used by senior management in deciding how to allocate capital resources among business segments. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating segment results. The GAAP measure most directly comparable to total segment gross operating margin is operating income. Our non-GAAP financial measure of total segment gross operating margin should not be considered as an alternative to GAAP operating income.

We define total segment gross operating margin as operating income before: (1) depreciation and amortization expense; (2) operating lease expenses for which we do not have the payment obligation; (3) gains and losses on the sale of assets; and (4) selling, general and administrative expenses. Gross operating margin is exclusive of other income and expense transactions, provision for income taxes, minority interest and extraordinary charges. Gross operating margin by segment is calculated by subtracting segment operating costs and expenses (net of the adjustments noted above) from segment revenues, with both segment totals before the elimination of intercompany transactions.

Segment revenues and expenses include intersegment and intrasegment transactions, which are generally based on transactions made at market-related rates. Our consolidated revenues reflect the elimination of all material intercompany (both intersegment and intrasegment) transactions.

We include equity earnings from unconsolidated affiliates in our measurement of segment gross operating margin. Our equity investments with industry partners are a vital component of our business strategy. They are a means by which we conduct our operations to align our interests with those of our customers, which may be a supplier of raw materials or a consumer of finished products. This method of operation also enables us to achieve favorable economies of scale relative to the level of investment and business risk assumed versus what we could accomplish on a stand-alone basis. Many of these businesses perform supporting or complementary roles to our other business operations. For example, we use the Promix NGL fractionator to process a portion of the mixed NGLs extracted by our gas plants. Another example is our use of the Dixie pipeline to transport propane sold to customers through our NGL marketing activities. See Note 8 for additional information regarding our related party relationships with unconsolidated affiliates.

Our revenues are derived from a wide customer base. All consolidated revenues were earned in the United States. Most of our plant-based operations are located primarily along the western Gulf Coast in Texas, Louisiana and Mississippi. Our pipelines and related operations are in a number of regions of the United States including the

Gulf of Mexico offshore Louisiana (certain natural gas pipelines); the south and southeastern United States (primarily in the Texas, Louisiana and Mississippi regions); and certain regions of the central and western United States. The Mid-America pipeline system extends from the Hobbs hub located on the Texas-New Mexico border to Wyoming along one route and to Minnesota, Wisconsin and Illinois along other routes. Our marketing activities are headquartered in Houston, Texas at our main office and service customers in a number of regions in the United States including the Gulf Coast, West Coast and Mid-Continent areas.

Consolidated property, plant and equipment and investments in and advances to unconsolidated affiliates are allocated to each segment on the basis of each asset's or investment's principal operations. The principal reconciling item between consolidated property, plant and equipment and segment property is construction-in-progress. Segment property represents those facilities and projects that contribute to gross operating margin and is net of accumulated depreciation on these assets. Since assets under construction do not generally contribute to segment gross operating margin, these assets are not included in the operating segment totals until they are deemed operational. Consolidated intangible assets and goodwill are allocated to the segments based on the classification of the assets to which they relate.

The following table shows our measurement of total segment gross operating margin for the periods indicated:

	For the Three Months Ended March 31,	
	2004	**2003**
Revenues (1)	$ 1,704,890	$ 1,481,586
Less: Operating costs and expenses (1)	(1,621,508)	(1,386,704)
Add: Equity in income of unconsolidated affiliates (1)	13,398	1,621
Depreciation and amortization in operating costs and expenses (2)	30,520	27,657
Retained lease expense, net in operating expenses allocable to us and minority interest (3)	2,274	2,274
Loss on sale of assets in operating costs and expenses (2)	98	4
Total non-GAAP gross operating margin	$ 129,672	$ 126,438

(1) These amounts are taken from our Statements of Consolidated Operations and Comprehensive Income.
(2) These non-cash expenses are taken from the operating activities section of our Statements of Consolidated Cash Flows.
(3) These non-cash expenses represent the value of the operating leases contributed by EPCO to us for which EPCO has retained the cash payment obligation (i.e., the "retained leases"). The value of the retained leases contributed directly to us is shown on our Statement of Consolidated Cash Flows under the line item titled "Operating lease expense paid by EPCO." That portion of the value contributed by a minority interest holder is a component of "Contributions from minority interests" as shown in the financing activities section of our Statement of Consolidated Cash Flows.

A reconciliation of our measurement of total non-GAAP gross operating margin to GAAP consolidated operating income (as shown on our Statements of Consolidated Operations and Comprehensive Income) follows:

	For the Three Months Ended March 31,	
	2004	**2003**
Operating income per GAAP	$ 87,314	$ 85,032
Adjustments to reconcile operating income per GAAP to non-GAAP total gross operating margin:		
Depreciation and amortization in operating costs and expenses	30,520	27,657
Retained lease expense, net in operating costs and expenses	2,274	2,274
Loss on sale of assets in operating costs and expenses	98	4
Selling, general and administrative costs	9,466	11,471
Total non-GAAP gross operating margin	$ 129,672	$ 126,438

Information by operating segment, together with reconciliations to the consolidated totals, is presented in the following table:

	Operating Segments					Adjs.	
	Fractionation	Pipelines	Processing	Octane Enhancement	Other	and Elims.	Consol. Totals
Revenues from third parties:							
Three months ended March 31, 2004	$ 227,403	$ 187,753	$ 1,106,307	$ 27,309	$ 815		$ 1,549,587
Three months ended March 31, 2003	204,490	201,893	941,686		713		1,348,782
Revenues from related parties:							
Three months ended March 31, 2004	285	51,806	103,212				155,303
Three months ended March 31, 2003	623	40,705	91,476				132,804
Intersegment and intrasegment revenues:							
Three months ended March 31, 2004	76,004	34,638	391,611	1,431		$ (503,684)	
Three months ended March 31, 2003	84,672	35,724	187,241		101	(307,738)	
Total revenues:							
Three months ended March 31, 2004	303,692	274,197	1,601,130	28,740	815	(503,684)	1,704,890
Three months ended March 31, 2003	289,785	278,322	1,220,403		814	(307,738)	1,481,586
Equity income in unconsolidated affiliates:							
Three months ended March 31, 2004	1,180	12,218					13,398
Three months ended March 31, 2003	284	4,778		(3,441)			1,621
Gross operating margin by individual business segment and in total:							
Three months ended March 31, 2004	30,260	82,985	18,065	(1,266)	(372)		129,672
Three months ended March 31 , 2003	29,047	71,932	29,956	(3,441)	(1,056)		126,438
Segment assets:							
At March 31, 2004	466,746	2,178,442	200,838	41,638	23,123	40,834	2,951,621
At December 31, 2003	471,221	2,188,694	163,199	42,220	23,739	74,432	2,963,505
Investments in and advances to unconsolidated affiliates (see Note 6):							
At March 31, 2004	89,041	644,252	33,000				766,293
At December 31, 2003	88,801	645,958	33,000				767,759
Intangible Assets (see Note 7):							
At March 31, 2004	67,923	9,601	185,938	1,609			265,071
At December 31, 2003	68,553	9,753	188,954	1,633			268,893
Goodwill (see Note 7) At March 31, 2004 and December 31, 2003	81,547	880					82,427

14. EARNINGS PER UNIT

Basic earnings per unit is computed by dividing net income or loss allocated to limited partner interests by the weighted-average number of common and subordinated units and Class B special units outstanding during a period. In general, diluted earnings per unit is computed by dividing net income or loss allocated to limited partner interests by the sum of:

- the weighted-average number of common and subordinated units and Class A and Class B special units outstanding during a period; and
- the number of incremental common units resulting from the assumed exercise of dilutive unit options outstanding during a period (the "incremental option units").

In a period of net operating losses, the Class A special units and incremental option units are excluded from the calculation of diluted earnings per unit due to their antidilutive effect. Treasury units are not considered to be outstanding units; therefore, they are excluded from the computation of both basic and diluted earnings per unit.

The dilutive incremental option units are calculated in accordance with the treasury stock method, which assumes that proceeds from the exercise of all in-the-money options at the beginning of each period are used to repurchase common units at average market value during the period. The amount of common units remaining after the proceeds are exhausted represents the potentially dilutive effect of the securities.

Beginning in August 2003, we started reissuing treasury units to satisfy our obligations under EPCO unit option agreements. The reissuance of these treasury units to satisfy EPCO's unit option liability has a dilutive effect on our earnings per unit. Prior to August 2003, EPCO had purchased practically all of the common units associated with its 1998 Plan in the open market. As a result, EPCO's unit option plan did not have any effect on our fully diluted earnings per unit in prior periods.

The amount of net income allocated to limited partner interests is derived by subtracting our General Partner's share of our net income from net income. The following table shows the allocation of net income to our General Partner for the periods indicated:

	For the Three Months Ended March 31,	
	2004	2003
Net income	$ 58,541	$ 40,505
Less incentive earnings allocations to General Partner	(6,277)	(3,770)
Net income available after incentive earnings allocation	52,264	36,735
Multiplied by General Partner ownership interest (1)	2.0%	1.0%
Standard earnings allocation to General Partner	$ 1,045	$ 367
Incentive earnings allocation to General Partner	$ 6,277	$ 3,770
Standard earnings allocation to General Partner	1,045	367
General partner interest in net income	$ 7,322	$ 4,137

(1) Our General Partner's ownership interest in us increased from 1% to 2% in December 2003 as a result of restructuring its overall ownership interest in us and our Operating Partnership.

The following table shows our calculation of limited partners' interest in net income, basic earnings per unit and diluted earnings per unit for the periods indicated:

	For the Three Months Ended March 31, 2004	2003
Income before change in accounting principle and general partner interest	$ 51,528	$ 40,505
Cumulative effect of change in accounting principle	7,013	
Net income	58,541	40,505
General partner interest in net income	(7,322)	(4,137)
Limited partners' interest in net income	$ 51,219	$ 36,368
BASIC EARNINGS PER UNIT		
Numerator		
Income before change in accounting principle and general partner interest	$ 51,528	$ 40,505
Cumulative effect of change in accounting principle	7,013	
General partner interest in net income	(7,322)	(4,137)
Limited partners' interest in net income	$ 51,219	$ 36,368
Denominator		
Common units outstanding	214,049	154,076
Subordinated units outstanding		32,115
Class B special units outstanding	4,414	
Total	218,463	186,191
Basic earnings per unit		
Income per unit before change in accounting principle and general partner interest	$ 0.24	$ 0.22
Cumulative effect of change in accounting principle	0.03	
General partner interest in net income	(0.03)	(0.02)
Limited partners' interest in net income	$ 0.24	$ 0.20
DILUTED EARNINGS PER UNIT		
Numerator		
Income before change in accounting principle and general partner interest	$ 51,528	$ 40,505
Cumulative effect of change in accounting principle	7,013	
General partner interest in net income	(7,322)	(4,137)
Limited partners' interest in net income	$ 51,219	$ 36,368
Denominator		
Common units outstanding	214,049	154,076
Subordinated units outstanding		32,115
Class A special units outstanding		10,000
Class B special units outstanding	4,414	
Incremental option units	497	
Total	218,960	196,191
Diluted earnings per unit		
Income per unit before change in accounting principle and general partner interest	$ 0.23	$ 0.21
Cumulative effect of change in accounting principle	0.03	
General partner interest in net income	(0.03)	(0.02)
Limited partners' interest in net income	$ 0.23	$ 0.19

15. CONDENSED FINANCIAL INFORMATION OF OPERATING PARTNERSHP

The Operating Partnership and its subsidiaries conduct substantially all of our business. We have no independent operations and no material assets outside of those of the Operating Partnership. In December 2003, we restructured our General Partner's ownership interest in us and the Operating Partnership from a 1% ownership in us and 1.0101% ownership in the Operating Partnership to a 2% ownership in us. As a result, our effective ownership in the Operating Partnership increased from 98.9899% to 100%.

The Operating Partnership has outstanding publicly traded debt securities consisting of its Senior Notes A, B, C and D. We act as guarantor of all of our Operating Partnership's consolidated debt obligations (including its publicly-traded debt securities), with the exception of the Seminole Notes. If the Operating Partnership were to default on any debt we guarantee, we would be responsible for full repayment of that obligation. Our guarantee of the Operating Partnership's debt obligations is full and unconditional. For additional information regarding our consolidated debt obligations, see Note 10.

The number and dollar amount of reconciling items between our consolidated financial statements and those of our Operating Partnership are insignificant. The primary reconciling items between the consolidated balance sheet of the Operating Partnership and our consolidated balance sheet are the treasury units we own directly and minority interest. The differences in consolidated net income are primarily dividends recognized by the 1999 Trust (which are eliminated in consolidation) and minority interest. The minority interest differences are attributable to the General Partner's 1.0101% ownership of the Operating Partnership prior to December 2003.

The following tables show condensed financial information for the Operating Partnership for the periods and at the dates indicated:

Condensed Consolidated Balance Sheets

	March 31, 2004	December 31, 2003
ASSETS		
Current assets	$ 686,728	$ 687,530
Property, plant and equipment, net	2,951,621	2,963,505
Investments in and advances to unconsolidated affiliates, net	766,293	767,759
Intangible assets, net	265,071	268,893
Goodwill	82,427	82,427
Deferred tax asset	8,784	10,437
Other assets	22,415	22,610
Total	$ 4,783,339	$ 4,803,161
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities	$ 767,363	$ 1,093,747
Long-term debt	2,195,876	1,899,548
Other liabilities	9,027	14,081
Minority interest	91,384	89,216
Partners' equity	1,719,689	1,706,569
Total	$ 4,783,339	$ 4,803,161
Total Operating Partnership debt obligations guaranteed by us	$ 2,179,000	$ 2,114,000

Condensed Consolidated Statements of Operations

	For the Three Months Ended March 31, 2004	2003
Revenues	$ 1,704,890	$ 1,481,586
Costs and expenses	1,630,711	1,397,896
Equity in income of unconsolidated affiliates	13,398	1,621
Operating income	87,577	85,311
Other income (expense)		
Interest expense	(32,618)	(41,911)
Other, net	1,569	2,977
Total other income (expense)	(31,049)	(38,934)
Income before provision for taxes, minority interest and change in accounting principle	56,528	46,377
Provision for taxes	(1,625)	(3,129)
Income before minority interest and change in accounting principle	54,903	43,248
Minority interest	(2,934)	(1,899)
Income before change in accounting principle	51,969	41,349
Cumulative effect of change in accounting principle	7,013	
Net income	$ 58,982	$ 41,349

16. SUBSEQUENT EVENTS

Interest Rate Hedging Program

In March 2004, we entered into forward starting interest rate swaps in anticipation of entering into permanent debt financing for the proposed merger with GulfTerra. In late April 2004, we terminated these arrangements and received approximately $104.5 million in cash. This amount will be amortized as a reduction in interest expense over the life of the future planned debt issuances, which are forecasted to take place during the second half of 2004. Please see Note 12 for additional information regarding these financial instruments.

May 2004 equity offering

In May 2004, we sold 15,000,000 common units to the public at an offering price of $21.00 per unit. Net proceeds from this offering, including our General Partner's proportionate net capital contribution of $6 million, were approximately $307 million after deducting applicable underwriting discounts, commissions and offering expenses of $14.3 million. The net proceeds from this offering, including our General Partner's proportionate net capital contribution, were used to repay in full our $225 million Interim Term Loan and to temporarily reduce borrowings under our revolving credit facilities.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

For the three months ended March 31, 2004 and 2003.

INTRODUCTION

Enterprise Products Partners L.P. including its consolidated subsidiaries is a publicly traded Delaware limited partnership listed on the NYSE under the ticker symbol "EPD." Unless the context requires otherwise, references to "we," "us," "our" or "Enterprise" are intended to mean the consolidated business and operations of Enterprise Products Partners L.P. Certain abbreviated entity names and other capitalized and industry terms are defined within the glossary of this quarterly report on Form 10-Q.

We were formed in April 1998 to own and operate certain NGL-related businesses of Enterprise Products Company ("EPCO"). We conduct substantially all of our business through a wholly owned subsidiary, Enterprise Products Operating L.P. (our "Operating Partnership"). We are owned 98% by our limited partners and 2% by Enterprise Products GP, LLC (our "General Partner"). We and our General Partner are affiliates of EPCO.

The following discussion and analysis should be read in conjunction with our unaudited consolidated financial statements and notes included under Item 1 of this quarterly report. Other risks involved in our business are discussed under "*Quantitative and Qualitative Disclosures about Market Risk*" included under Item 3 of this quarterly report.

Cautionary Statement regarding Forward-Looking Information and Risk Factors

This quarterly report contains various forward-looking statements and information that are based on our beliefs and those of our General Partner, as well as assumptions made by us and information currently available to us. When used in this document, words such as "anticipate," "project," "expect," "plan," "goal," "forecast," "intend," "could," "believe," "may" and similar expressions and statements regarding our plans and objectives for future operations, are intended to identify forward-looking statements. Although we and our General Partner believe that such expectations reflected in such forward-looking statements are reasonable, neither we nor our General Partner can give any assurances that such expectations will prove to be correct. Such statements are subject to a variety of risks, uncertainties and assumptions. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, our actual results may vary materially from those anticipated, estimated, projected or expected. You should not put undue reliance on any forward-looking statements. When considering forward-looking statements, please read our summarized "*Risk Factors*" below.

Risk Factors

Among the key risk factors that may have a direct impact on our results of operations and financial condition are:

- A reduction in demand for our products by the petrochemical, refining or heating industries could adversely affect our results of operations.
- A decline in the volume of NGLs delivered to our facilities could adversely affect our results of operations.
- A decrease in the difference between NGL product prices and natural gas prices may result in lower margins with respect to the margin sharing component on volumes of natural gas processed under fee-based arrangements with margin sharing mechanisms.
- Our business requires extensive credit risk management that may not be adequate to protect against customer nonpayment.
- Acquisitions and expansions may affect our business by substantially increasing the level of our indebtedness and contingent liabilities and increasing our risks of being unable to effectively integrate these new operations.

- Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to entity-level taxation by states. If the IRS treats us as a corporation or we become subject to entity-level taxation for state tax purposes, it would substantially reduce distributions to our Unitholders and our ability to make payments on our debt securities.
- We have leverage that may restrict our future financial and operating flexibility.
- Terrorist attacks aimed at our facilities could adversely affect our business.

RECENT DEVELOPMENTS

Proposed merger with GulfTerra

We expect to complete the proposed merger with GulfTerra in the second half of 2004. A number of conditions must be satisfied before we can complete the merger, including approval by the unitholders of both Enterprise and GulfTerra and the expiration or termination of applicable waiting periods under the Hart-Scott-Rodino Antitrust Improvements Act of 1974. While we cannot predict if and when all of the conditions of the proposed merger will be satisfied, we expect to complete the transaction in the second half of 2004.

In April 2004, we and El Paso agreed to amend certain terms of the merger agreement. In the original transaction, in connection with Step Two of the proposed merger (as described below), El Paso was to exchange its 50% membership interest in GulfTerra GP for a 50% membership interest in our General Partner. Under the amended transaction, in connection with Step Two of the proposed merger, El Paso will still contribute its 50% membership interest in GulfTerra GP to our General Partner, but in exchange will receive a 9.9% membership interest in our General Partner and $370 million in cash. The remaining 90.1% membership interest in our General Partner will continue to be owned by affiliates of EPCO. The funds for the $370 million payment to El Paso will be provided by affiliates of EPCO.

El Paso, through its 9.9% membership in our General Partner, will have protective veto rights on certain transactions, such as any merger of our General Partner or any merger involving and resulting in a change of control of us. In addition, commencing six months after the closing of the proposed merger, or earlier in certain circumstances, El Paso will have the right to exchange its 9.9% membership interest in our General Partner for a number of common units equal to 9.9% of the aggregate quarterly distribution paid by us to our General Partner divided by the preceding quarterly distribution per unit paid to the holders of our common units. Our General Partner may elect to deliver (i) Enterprise common units owned by our General Partner (which it may acquire from an affiliate of EPCO), (ii) an equivalent cash amount or (iii) a combination of cash or common units. Three and a half years after closing of the proposed merger, the affiliates of EPCO that own the 90.1% membership interest in our General Partner can require El Paso to contribute all of its membership interest in our General Partner to the General Partner.

In general, the proposed merger with GulfTerra involves the following three steps:

- *Step One*. On December 15, 2003, we purchased a 50% membership interest in GulfTerra's general partner ("GulfTerra GP") for $425 million. GulfTerra's general partner owns a 1% general partner interest in GulfTerra. This investment is accounted for using the equity method and is already recorded in our historical balance sheet at December 31, 2003. This transaction is referred to as Step One of the proposed merger and will remain in effect even if the remainder of the proposed merger and post-merger transactions, which are referred to as Step Two and Step Three, do not occur.

- *Step Two*. If all necessary regulatory and unitholder approvals are received and the other merger agreement conditions are either fulfilled or waived and the following steps are consummated, we will own 100% of the limited and general partner interests in GulfTerra. At that time, the proposed merger will be accounted for using the purchase method, and GulfTerra will be a consolidated subsidiary of Enterprise. Step Two of the proposed merger includes the following transactions:

    - El Paso's exchange of its remaining 50% membership interest in GulfTerra GP for a cash payment by our General Partner of $370 million (which will not be funded or reimbursed by us) and a 9.9% membership in our General Partner, and the subsequent capital contribution by our General Partner of such 50% membership interest in GulfTerra GP to us (without increasing our General Partner's interest in our earnings or cash distributions).

    - Our purchase of 10,937,500 GulfTerra Series C units and 2,876,620 GulfTerra common units owned by El Paso for $500 million.

    - The exchange of each remaining GulfTerra common unit for 1.81 Enterprise common units, resulting in the issuance of approximately 104.6 million of our common units to GulfTerra unitholders.

- *Step Three*. Immediately after Step Two is completed, we expect to acquire certain South Texas midstream energy assets from El Paso for $150 million plus the value of then existing inventories related to such assets.

We anticipate that our obligations under Steps Two and Three of the proposed merger to pay El Paso $650 million will be financed initially with a short-term acquisition term loan and with borrowings under our revolving credit facilities.

Our preliminary estimate of the total consideration for Steps One, Two and Three we would pay or issue is approximately $4.0 billion. For a period of three years following the closing of the proposed merger, at our request El Paso will provide certain support services to GulfTerra similar to those provided by El Paso prior to the closing of the merger. GulfTerra will reimburse El Paso for 110% of its direct costs for such services (excluding any overhead costs). El Paso will make transition support payments to us in annual amounts of $18 million, $15 million and $12 million for the first, second and third years of such period, respectively, payable in twelve equal monthly installments for each such year. These transition support payments are included in our preliminary estimate of total consideration.

To review a copy of the merger agreement and related transaction documents, please read our Current Reports on Form 8-K filed with the SEC on December 15, 2003 and April 21, 2004.

Recontracting of natural gas processing agreements

We recently completed a program to convert essentially all of our traditional keepwhole contracts to other types of processing arrangements where the producer assumes all or most of the direct commodity price risk between NGLs and natural gas. These new arrangements include simple fee-based contracts, hybrid fee-based contracts with margin-sharing provisions and percent-of-liquids agreements. We began this effort in 2003. Prior to starting the recontracting effort, approximately 70% of the natural gas we processed was done so under traditional keepwhole arrangements. Under these arrangements, the volatility in natural gas prices since 2000 created large swings in the operating results of our natural gas processing business, which in turn did not provide us with a consistent return on our investment.

Beginning in the second quarter of 2004, approximately two-thirds of the 2.1 Bcf/d natural gas we expect to process will be done so under contracts containing a fee-based component. This compares to 50 MMcf/d of fee-based volumes prior to recontracting. Approximately one-third of the natural gas we expect to process, or 0.7 Bcf/d, will be under percent-of-liquids contracts compared to 0.5 Bcf/d processed under such arrangements previously. We forecast that our share of NGLs earned under percent-of-liquids contracts will increase to approximately 5 MBPD from the 4 MBPD earned prior to restructuring our processing agreements.

To provide our partnership with the opportunity to earn additional gross operating margin above that provided by the fee-based and percent-of-liquids arrangements and to align our interest with certain producers, some of our contracts provide a mechanism for us to participate in margin-sharing arrangements with the producer (in addition to the fees we would earn) without exposing our partnership to the risk of incremental cash losses. Approximately 50% of the natural gas we expect to process during 2004 is under these margin-sharing arrangements.

We believe these contract revisions will result in our being fairly compensated for this critical midstream service while providing producers with the assurance that their processing agreements with us are operative regardless of the natural gas price. We also believe that these new agreements will (1) provide us with a more consistent base of revenue and gross operating margin from our natural gas processing business, (2) greatly reduce the direct commodity price risk that previously existed under traditional keepwhole arrangements and (3) provide for a more reliable return on our investment.

Interest Rate Hedging Program

In March 2004, we entered into forward starting interest rate swaps in anticipation of entering into permanent debt financing for the proposed merger with GulfTerra. In late April 2004, we terminated these arrangements and received approximately $104.5 million in cash. For additional information regarding these financial instruments, please read "*Interest rate risk*" included under Item 3 of this quarterly report.

May 2004 equity offering

In May 2004, we sold 15,000,000 common units to the public at an offering price of $21.00 per unit. Net proceeds from this offering, including our General Partner's proportionate net capital contribution of $6 million, were $307 million after deducting applicable underwriting discounts, commissions and offering expenses of $14.3 million. The net proceeds from this offering, including our General Partner's proportionate net capital contribution, were used to repay in full our $225 million Interim Term Loan and to temporarily reduce borrowings under our revolving credit facilities.

OUR RESULTS OF OPERATIONS

We have five reportable business (or operating) segments: Pipelines, Fractionation, Processing, Octane Enhancement and Other. Pipelines consists of NGL, petrochemical and natural gas pipeline systems, storage and import/export terminal services. Fractionation primarily includes NGL fractionation, isomerization and propylene fractionation. Processing includes our natural gas processing business and related NGL marketing activities. Octane Enhancement represents our investment in a facility that produces motor gasoline additives to enhance octane (currently producing MTBE and isobutylene). The Other business segment consists of fee-based marketing services and various operational support activities.

We evaluate segment performance based on the non-GAAP financial measure of gross operating margin. Gross operating margin (either in total or by individual segment) is an important performance measure of the core profitability of our operations. This measure forms the basis of our internal financial reporting and is used by senior management in deciding how to allocate capital resources among business segments. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating segment results. The GAAP measure most directly comparable to total segment gross operating margin is operating income. Our non-GAAP financial measure of total segment gross operating margin should not be considered as an alternative to GAAP operating income.

We define total segment gross operating margin as operating income before: (1) depreciation and amortization expense; (2) operating lease expenses for which we do not have the payment obligation; (3) gains and losses on the sale of assets; and (4) selling, general and administrative expenses. Gross operating margin is exclusive of other income and expense transactions, provision for income taxes, minority interest and extraordinary charges. Gross operating margin by segment is calculated by subtracting segment operating costs and expenses (net of the adjustments noted above) from segment revenues, with both segment totals before the elimination of intercompany transactions. In accordance with GAAP, intercompany accounts and transactions are eliminated in consolidation.

We include equity earnings from unconsolidated affiliates in our measurement of segment gross operating margin. Our equity investments with industry partners are a vital component of our business strategy. They are a means by which we conduct our operations to align our interests with those of our customers, which may be a supplier of raw materials or a consumer of finished products. This method of operation also enables us to achieve favorable economies of scale relative to the level of investment and business risk assumed versus what we could accomplish on a stand-alone basis. Many of these businesses perform supporting or complementary roles to our other business operations. For additional information regarding our business segments, please read Note 13 of our Notes to Unaudited Consolidated Financial Statements included under Item 1 of this quarterly report.

The following table summarizes our consolidated revenues, costs and expenses, equity in income of unconsolidated affiliates and operating income for the periods indicated (dollars in thousands):

	For the Three Months Ended March 31,	
	2004	**2003**
Revenues	$ 1,704,890	$ 1,481,586
Operating costs and expenses	1,621,508	1,386,704
Selling, general and administrative costs	9,466	11,471
Equity in income (loss) of unconsolidated affiliates	13,398	1,621
Operating income	87,314	85,032

A reconciliation of our measurement of total non-GAAP gross operating margin to GAAP consolidated operating income (as shown on our Statements of Consolidated Operations and Comprehensive Income) follows:

	For the Three Months Ended March 31,	
	2004	**2003**
Operating income per GAAP	$ 87,314	$ 85,032
Adjustments to reconcile operating income per GAAP		
to non-GAAP total gross operating margin:		
Depreciation and amortization in operating costs and expenses	30,520	27,657
Retained lease expense, net in operating costs and expenses	2,274	2,274
Loss on sale of assets in operating costs and expenses	98	4
Selling, general and administrative costs	9,466	11,471
Total non-GAAP gross operating margin	$ 129,672	$ 126,438

EPCO subleases to us certain equipment located at our Mont Belvieu facility and 100 railroad tankcars for $1 dollar per year. These subleases (the "retained lease expense" in the previous table) are part of the Administrative Services Agreement that we executed with EPCO in connection with our formation in 1998. EPCO holds these items pursuant to operating leases for which it has retained the corresponding cash lease payment obligation. Operating costs and expenses (as shown in the Statements of Consolidated Operations and Comprehensive Income) treat the lease payments being made by EPCO as a non-cash related party operating expense, with the offset to Partners' Equity on the Consolidated Balance Sheets recorded as a general contribution to the Company. Apart from the partnership interests we granted to EPCO at our formation, EPCO does not receive any additional ownership rights as a result of its contribution to us of the retained leases.

EPCO also assigned to us the purchase options associated with these leases. We notified the lessor of the isomerization unit associated with the retained leases of our intent to exercise the purchase option relating to this equipment in 2004. Under the terms of the lease agreement for the isomerization unit, we have the option to purchase the equipment at the lesser of fair value or $23.1 million. Should we decide to exercise all of the remaining purchase options associated with the retained leases (which are also at fair value), up to an additional $2.8 million would be payable in 2004, $2.3 million in 2008 and $3.1 million in 2016.

Our gross operating margin amounts by segment were as follows for the periods indicated (dollars in thousands):

	For the Three Months Ended March 31,	
	2004	**2003**
Gross operating margin by segment:		
Pipelines	$ 82,985	$ 71,932
Fractionation	30,260	29,047
Processing	18,065	29,956
Octane enhancement (1)	(1,266)	(3,441)
Other	(372)	(1,056)
Total gross operating margin	$ 129,672	$ 126,438

(1) Comparability of gross operating margin for the Octane Enhancement segment for the periods presented is impacted due to ownership changes in the octane enhancement facility that occurred in 2003. Prior to September 30, 2003, we owned a 33.3% partnership interest in the entity that owns this facility, the financial results of which were accounted for using the equity method of accounting (i.e., through equity earnings). On September 30, 2003, we increased our ownership interest in the entity that owns this facility to 66.7%. As a result of this increased ownership interest, beginning with the fourth quarter of 2003, the financial results of this facility are now consolidated into our financial statements (i.e., 100% of this facility's gross operating margin is reflected in the Octane Enhancement segment as opposed to 33.3% of its net income or loss through equity earnings prior to consolidation).

Our significant pipeline throughput, plant production and processing volumetric data were as follows for the periods indicated (on a net basis, taking into account our ownership interests):

	For the Three Months Ended March 31,	
	2004	**2003**
Pipelines, net volumes as shown:		
NGL and petrochemical liquids pipelines (MBPD, net)	1,423	1,313
Natural gas pipelines (BBtus per day, net)	1,075	1,034
Combined energy equivalent (MBPD, net)	1,706	1,585
Fractionation, net volumes in MBPD:		
NGL fractionation	229	235
Propylene fractionation	54	60
Isomerization	60	80
Natural gas processing, net volumes as shown:		
Fee-based natural gas processing (MMcf per day, net)	362	65
Equity NGL production (MBPD, net)	64	54
Octane enhancement, net volumes in MBPD	5	3

The following table illustrates selected average quarterly industry index prices for natural gas, crude oil, selected NGL and petrochemical products and indicative gas processing gross spreads since the beginning of 2002:

	Natural Gas, $/MMBtu	Crude Oil, $/barrel	Ethane, $/gallon	Propane, $/gallon	Normal Butane, $/gallon	Isobutane, $/gallon	Natural Gasoline, $/gallon	Polymer Grade Propylene, $/pound	Refinery Grade Propylene, $/pound	Indicative Gas Processing Gross Spread, $/gallon
	(1)	(2)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(3)
2002										
1st Quarter	$2.34	$21.41	$0.22	$0.30	$0.38	$0.44	$0.47	$0.16	$0.12	$0.12
2nd Quarter	$3.38	$26.26	$0.26	$0.40	$0.48	$0.51	$0.58	$0.20	$0.17	$0.10
3rd Quarter	$3.16	$28.30	$0.26	$0.42	$0.52	$0.58	$0.61	$0.21	$0.16	$0.14
4th Quarter	$3.99	$28.33	$0.31	$0.49	$0.60	$0.63	$0.66	$0.20	$0.15	$0.13
Average for Year	$3.22	$26.08	$0.26	$0.40	$0.50	$0.54	$0.58	$0.20	$0.15	$0.12
2003										
1st Quarter	$6.58	$34.12	$0.43	$0.65	$0.76	$0.80	$0.85	$0.24	$0.21	$0.05
2nd Quarter	$5.40	$29.04	$0.39	$0.53	$0.58	$0.62	$0.65	$0.25	$0.19	$0.04
3rd Quarter	$4.97	$30.21	$0.37	$0.56	$0.67	$0.68	$0.73	$0.21	$0.15	$0.10
4th Quarter	$4.58	$31.18	$0.40	$0.58	$0.73	$0.71	$0.75	$0.22	$0.16	$0.17
Average for Year	$5.38	$31.14	$0.40	$0.58	$0.68	$0.70	$0.74	$0.23	$0.18	$0.09
2004										
1st Quarter	$5.69	$35.25	$0.43	$0.66	$0.76	$0.76	$0.87	$0.29	$0.26	$0.13

(1) Natural gas, NGL, polymer grade propylene and refinery grade propylene prices represent an average of various commercial index prices including OPIS and CMAI. Natural gas price is representative of Henry-Hub I-FERC. NGL prices are representative of Mont Belvieu Non-TET pricing. Refinery grade propylene represents an average of CMAI spot prices. Polymer-grade propylene represents average CMAI contract pricing.
(2) Crude oil price is representative of an index price for West Texas Intermediate.
(3) The Indicative Gas Processing Gross Spread is a relative measure used by the NGL industry as an indicator of the gross economic benefit derived from extracting NGLs from natural gas production on the U.S. Gulf Coast. Specifically, it is the amount by which the economic value of a composite gallon of NGLs exceeds the value of the equivalent amount of energy of natural gas based on NGL and natural gas prices on the U.S. Gulf Coast. It is assumed that a gallon of NGLs is comprised of 33% ethane, 32% propane, 11% normal butane, 8% isobutane and 16% natural gasoline. The value of a composite gallon of NGLs is determined by multiplying these component percentages by industry index prices listed in the table above. The value of the equivalent amount of energy of natural gas to one gallon of NGLs is 8.9% of the price of a MMBtu of natural gas. The Indicative Gas Processing Gross Spread does not consider the operating and fuel costs incurred by a natural gas processing plant to extract the NGLs nor the transportation and fractionation costs to deliver the NGLs and natural gas to market.

General business environment

As a result of continued improvement of the economy, we have experienced an increase in demand for our midstream energy services when compared to the second half of 2003. Our largest NGL customers are experiencing stronger demand for their products and expect that this demand will be sustainable throughout 2004. In addition, natural gas prices have decreased relative to other forms of energy. This has made NGLs more competitive versus crude oil derivatives such as naphtha and gas oil for use as a feedstock in ethylene production. As a result, demand for ethane has increased. Average ethane demand by the ethylene industry for the first quarter of 2004 was 718 MBPD, which is comparable to the fourth quarter of 2003 and represents a 13% increase over ethane demand rates of the second and third quarters of 2003. The five-year average demand for ethane by the ethylene industry is approximately 750 MBPD.

Three months ended March 31, 2004 compared to three months ended March 31, 2003

Revenues for the first quarter of 2004 increased $223.3 million over those recorded during the same period in 2003 primarily due to higher NGL marketing revenues resulting from an increase in sales volumes. Likewise, operating costs and expenses increased $234.8 million quarter-to-quarter primarily due to an increase in cost of sales related to NGL marketing activities. The weighted-average NGL price was 64 CPG during the first quarter of 2004 compared to 63 CPG during the first quarter of 2003. Natural gas prices averaged $5.69 per MMBtu during the 2004 period versus $6.58 per MMBtu during the 2003 period.

Earnings from equity method unconsolidated affiliates increased $11.8 million quarter-to-quarter primarily due to $10.6 million recorded from GulfTerra GP in the first quarter of 2004. We acquired a 50% membership interest in GulfTerra GP from El Paso in December 2003. Selling, general and administrative costs decreased $2 million quarter-to-quarter. The first quarter of 2003 includes amounts paid to Williams for transition services that were discontinued in February 2003 when we began operating the Mid-America and Seminole pipeline systems. As a result of the aforementioned results, operating income increased $2.3 million quarter-to-quarter.

Interest expense decreased $9.3 million quarter-to-quarter primarily due to $11.3 million of unamortized loan costs which were expensed during the first quarter of 2003 when we repaid the bridge loan financing associated with our acquisition of interests in the Mid-America and Seminole pipelines. When compared to the first quarter of 2003, dividend income was $1.4 million lower due to a decrease in dividends received from VESCO.

The $7.0 million benefit recorded as a cumulative effect of change in accounting principle is due to our BEF subsidiary changing its method of accounting for planned major maintenance activities. For additional information regarding this non-cash item, please read " – *Other items – Cumulative effect of change in accounting principle recorded in first quarter of 2004*" on page 47. Including this adjustment, net income was $58.5 million for the first quarter of 2004 compared to $40.5 million for the first quarter of 2003.

The following information highlights the significant quarter-to-quarter variances in gross operating margin by business segment:

Pipelines. Gross operating margin from our Pipelines segment was $83.0 million for the first quarter of 2004 compared to $71.9 million for the first quarter of 2003. On an energy-equivalent basis, net pipeline throughput was 1,706 MBPD for the 2004 period versus 1,585 MBPD for the 2003 period. Gross operating margin for the first quarter of 2004 includes $10.6 million of equity earnings from GulfTerra GP. On a quarter-to-quarter basis, our Mid-America and Seminole pipelines experienced a $4.5 million decrease in gross operating margin despite a 15 MBPD increase in volumes. Gross operating margin for these systems was affected by lower revenues in connection with incentive tariffs granted to certain customers to ship NGLs on these systems.

As a result of stronger demand for natural gas, gross operating margin from Acadian Gas increased $1.4 million quarter-to-quarter. Natural gas throughput on this system increased 85 BBtu/d. Gross operating margin from our NGL and petrochemical storage business was $3.5 million higher quarter-to-quarter as a result of lower storage well charges. Our NGL import facility posted a $1.4 million increase in gross operating margin quarter-to-quarter primarily due to a 48 MBPD increase in import volumes. Gross operating margin on our Lou-Tex NGL pipeline decreased $3.0 million quarter-to-quarter as a result of a 21 MBPD decrease in volumes attributable to reduced NGL shipments from Louisiana to Texas.

Fractionation. Gross operating margin from our Fractionation segment was $30.3 million for the first quarter of 2004 compared to $29.0 million for the first quarter of 2003. Gross operating margin from NGL fractionation increased $0.8 million quarter-to-quarter. NGL fractionation volumes were 229 MBPD during the first quarter of 2004 versus 235 MBPD during the same period in 2003. Gross operating margin from our Norco facility increased $3.1 million quarter-to-quarter primarily due to a 30 MBPD increase in volumes. Norco volumes increased during the first quarter of 2004 as a result of an expansion of the facility completed during the fourth quarter of 2004. This expansion allowed Norco to fractionate volumes that had been processed at either our Toca-Western facility or transported on our Lou-Tex NGL pipeline to Mont Belvieu for fractionation. Gross operating margin from our Mont Belvieu facility decreased by $1.5 million quarter-to-quarter on a 20 MBPD decrease in volumes primarily due to competitive pressures at this industry hub.

Gross operating margin from propylene fractionation increased $4.9 million quarter-to-quarter due to an increase in petrochemical marketing sales margins. Propylene fractionation volumes were 54 MBPD during the 2004 period compared to 60 MBPD during the 2003 period. Gross operating margin from isomerization decreased $2.6 million quarter-to-quarter primarily due to lower processing volumes and by-product revenues. Isomerization volumes were 60 MBPD in the first quarter of 2004 compared to 80 MBPD in the first quarter of 2003. The decrease in isomerization volumes is attributable to maintenance and other downtime at a large third party isomerization customer and at BEF.

Processing. Gross operating margin from our Processing segment was $18.1 million for the first three months of 2004 compared to $30.0 million for the first three months of 2003. Gross operating margin from our gas processing plants increased $4.9 million quarter-to-quarter, but was offset by a $16.6 million decrease in margin from our NGL marketing activities. NGL marketing results for the 2003 period benefited from unusually strong demand for propane and normal butane. Commodity hedging results for both periods were insignificant. Equity NGL volumes for the first quarter of 2004 were 64 MBPD compared to 54 MBPD during the first quarter of 2003. Fee-based processing volumes were 362 Mmcf/d for the 2004 period compared to 65 Mmcf/d for the 2003 period.

We recently completed a program to convert essentially all of our traditional keepwhole contracts to other types of processing arrangements where the producer assumes all or most of the direct commodity price risk between NGLs and natural gas. These new arrangements include simple fee-based contracts, hybrid fee-based contracts with margin-sharing provisions and percent-of-liquids agreements. For additional information regarding the restructuring of our natural gas processing mix, please read "*– Recent Developments – Recontracting of natural gas processing agreements*."

Octane enhancement. Gross operating margin for the Octane Enhancement segment was a loss of $1.3 million for the first quarter of 2004 versus a loss of $3.4 million for the first quarter of 2003. Upon our acquisition of an additional 33.3% partnership interest in BEF on September 30, 2003, it became a majority owned consolidated subsidiary of ours. Prior to this date, BEF was accounted for as an equity method unconsolidated affiliate. The quarter-to-quarter improvement in underlying operating results is primarily due to increased sales margins during the periods in which the facility was operational during each quarter. In addition, BEF changed the method it uses to account for planned major maintenance activities from the accrue-in-advance method to the expense-as-incurred method effective January 1, 2004. As a result of this change, turnaround-related operating expenses decreased $2.2 million quarter-to-quarter.

OUR LIQUIDITY AND CAPITAL RESOURCES

General

Our primary cash requirements, in addition to normal operating expenses and debt service, are for capital expenditures, business acquisitions and distributions to our partners. We expect to fund our short-term needs for such items as operating expenses and sustaining capital expenditures with operating cash flows. Capital expenditures for long-term needs resulting from internal growth projects and business acquisitions are expected to be funded by a variety of sources including (either separately or in combination) cash flows from operating activities, borrowings under commercial bank credit facilities, the issuance of additional partnership equity and public or private placement debt. We expect to fund cash distributions to partners primarily with operating cash flows. Our debt service requirements are expected to be funded by operating cash flows and/or refinancing arrangements.

As noted above, certain of our liquidity and capital resource requirements are fulfilled by borrowings made under debt agreements and/or proceeds from the issuance of additional partnership equity. At March 31, 2004, we had approximately $2.2 billion in principal outstanding under various debt agreements. On that date, total borrowing capacity under our revolving commercial bank credit facilities was $500 million of which $248.7 million was unused. For additional information regarding our debt, please read " – *Our debt obligations.*"

We currently have on file with the SEC a $1.5 billion universal shelf registration statement covering the issuance of an unallocated amount of partnership equity or public debt obligations (separately or in combination). In June 2003, we sold 11,960,000 common units under this registration statement which reduced the amount available for future offerings to approximately $1.2 billion. In May 2004, we sold 15,000,000 common units under this registration statement from which we received net proceeds of $307 million, including our General Partner's proportionate net capital contribution of $6 million. As a result of our May 2004 offering, the amount available for future offerings under this shelf registration statement was reduced to $0.9 billion.

In April 2004, we filed a new registration statement with the SEC covering an additional 10,000,000 common units issuable under our Distribution Reinvestment Plan (or "DRIP"). The DRIP provides unitholders of record and beneficial owners of our common units a voluntary means by which they can increase the number of common units they own by reinvesting the quarterly cash distributions they would otherwise receive in the purchase of additional common units. The new registration statement increased the number of common units issuable under the DRIP from 5,000,000 to 15,000,000. We expect to use the cash generated from this reinvestment program for general partnership purposes. Since its inception in August 2003, we have issued 3,891,687 common units under this program generating net proceeds (including our General Partner's proportionate net capital contributions) of approximately $84 million. This amount includes 1,053,510 common units issued under this program in February 2004 which generated proceeds of approximately $23 million.

To support our growth objectives and financial flexibility, EPCO has reinvested approximately $75 million of its cash distributions since August 2003 through the DRIP (including $20 million in February 2003). In addition, EPCO has announced that it expects to reinvest an additional $120 million of its anticipated quarterly distributions through the first quarter of 2005.

If deemed necessary, we believe that additional financing arrangements can be obtained on reasonable terms. Furthermore, we believe that maintenance of our investment grade credit ratings combined with a continued ready access to debt and equity capital at reasonable rates and sufficient trade credit to operate our businesses efficiently provide a solid foundation to meet our long and short-term liquidity and capital resource requirements.

The following discussions highlight significant quarter-to-quarter comparisons in consolidated operating, investing and financing cash flows:

	For the Three Months Ended March 31, 2004	For the Three Months Ended March 31, 2003
Net income	$ 58,541	$ 40,505
Adjustments to reconcile net income to cash flows provided by (used for) operating activities before changes in operating accounts:		
Depreciation and amortization	31,383	39,261
Distributions received from unconsolidated affiliates: (1)		
GulfTerra GP (2)	10,642	
Other equity method investments (3)	5,040	15,626
Equity in income of unconsolidated affiliates: (1)		
GulfTerra GP (2)	(10,554)	
Other equity method investments (4)	(2,844)	(1,621)
Decrease (increase) in restricted cash (5)	5,825	(10,006)
Cumulative effect of change in accounting principle	(7,013)	
Other	7,016	7,281
Cash flow from operating activities before changes in operating accounts	98,036	91,046
Net effect of changes in operating accounts	(68,431)	50,497
Operating activities cash flows	$ 29,605	$ 141,543

(1) Distributions from unconsolidated affiliates and equity in income of unconsolidated affiliates have been presented in a manner to aid in comparability between periods.
(2) We acquired our interest in GulfTerra GP in December 2003.
(3) The 2003 period includes $5.1 million of cash distributions attributable to unconsolidated affiliates which became consolidated subsidiaries in 2003.
(4) The 2003 period includes $1.6 million of losses attributable to unconsolidated affiliates which became consolidated subsidiaries in 2003.
(5) Restricted cash consists of amounts held by a brokerage firm as margin deposits associated with our financial instruments portfolio and for the physical purchase of natural gas made on the NYMEX exchange.

Operating activities cash flows primarily reflect net income adjusted for depreciation, amortization and similar non-cash amounts; equity earnings and cash distributions from unconsolidated affiliates and changes in operating accounts. The net effect of changes in operating accounts is generally the result of timing of sales and purchases near the end of each period. Cash flow from operations is primarily based on earnings from our business activities. As a result, these cash flows are exposed to certain risks. The products that we process, sell or transport are principally used as feedstocks in petrochemical manufacturing, in the production of motor gasoline and as fuel for residential, agricultural and commercial heating. Reduced demand for our products or services by industrial customers, whether because of general economic conditions, reduced demand for the end products made with our products or increased competition from petroleum-based products due to pricing differences or other reasons could have a negative impact on our earnings and thus the availability of cash from operating activities. Other risks include fluctuations in NGL and energy prices, competitive practices in the midstream energy industry and the impact of operational and systems risks. For additional information regarding risk factors pertinent to our business, please read "*Cautionary Statement Regarding Forward-Looking Information and Risk Factors*" on page 29 of this quarterly report.

Three months ended March 31, 2004 compared to three months ended March 31, 2003

Operating activities cash flows. Cash flow from operating activities was $29.6 million during the first three months of 2004 compared to $141.5 million for the same period in 2003. As shown in the preceding table, cash flow before the net effect of changes in operating accounts was an inflow of $98 million for the 2004 period versus $91 million for the 2003 period. We believe that cash flow from operating activities before the net effect of changes in operating accounts is an important measure of our ability to generate core cash flows from our assets and other investments.

The $7 million increase in this element of our operating cash flows is primarily due to (i) a decrease in restricted cash and (ii) our receipt of a special distribution in the first quarter of 2003 of approximately $5 million from our Starfish unconsolidated affiliate in connection with the settlement of a rate case. The $7.9 million decrease in depreciation and amortization is primarily due to unamortized loan costs we expensed during the first quarter of 2003 when we repaid the bridge loan financing associated with our acquisition of interests in the Mid-America and Seminole pipelines. Earnings from equity method unconsolidated affiliates increased $11.8 million quarter-to-quarter primarily due to the $10.6 million we recorded during the first quarter of 2004 from our investment in GulfTerra GP. The $7.0 million benefit, recorded as a cumulative effect of change in accounting principle, is due to our consolidated BEF subsidiary changing its method of accounting for planned major maintenance activities. For additional information regarding this non-cash item, please read " – *Other items – Cumulative effect of change in accounting principle recorded in first quarter of 2004*" on page 47. The quarter-to-quarter fluctuation in the restricted cash balance is primarily due to the timing of physical purchases of natural gas on the NYMEX exchange.

The net effect of changes in operating accounts is generally the result of timing of cash receipts from sales and cash payments for inventory, purchases and other expenses near the end of each period. Approximately two-thirds of the change in this component of our cash flows relates to net cash inflows from inventory reductions during the first quarter of 2003 versus modest net cash outlays for inventory during the first quarter of 2004. An increase in NGL prices during the first quarter of 2003 relative to our cost of inventory led us to monetize a portion of our inventory.

Investing activities cash flows. For the three months ended March 31, 2004 and 2003, we used $15.8 million and $73.1 million in cash, respectively, for investing activities. Capital expenditures were $15.0 million for the 2004 period versus $23.8 million for the 2003 period. For additional information regarding our capital expenditures, please read " – *Capital spending*" on page 43. During the first quarter of 2003, we used $28.8 million to purchase the Port Neches Pipeline and the remaining 50% ownership interests in EPIK. Our investments in and advances to unconsolidated affiliates for the first three months of 2003 included amounts we contributed to our Gulf of Mexico natural gas pipeline investments for their expansion capital projects.

Financing activities cash flows. Our financing activities were a cash inflow of $0.5 million during the first three months of 2004 compared to an outflow of $59.7 million for the same period during 2003. For the first quarter of 2004, our net borrowings under debt agreements were $65 million compared to net repayments of $244.8 million during the first quarter of 2003. During the 2003 period, we made net repayments on our debt obligations using proceeds from our January 2003 common unit offering. The 2003 period also reflects the Operating Partnership's issuance of Senior Notes C ($350 million in principal amount) and Senior Notes D ($500 million in principal amount) and the repayment of $1.0 billion that was outstanding under the bridge loan financing we used to purchase interests in the Mid-America and Seminole pipelines.

Cash distributions to partners increased from $69.2 million during the first quarter of 2003 to $91.3 million during the same period in 2004. The increase in cash distributions is primarily due to an increase in both the declared quarterly distribution rates and the number of units eligible for distributions. Future cash distributions to partners will increase as a result of our periodic issuance of common units under the DRIP and equity offerings.

Net proceeds from the sale of common units were $23.1 million during the first quarter of 2004 compared to $258.1 million for the same period in 2003. Both amounts include our General Partner's net proportionate capital contributions. In May 2004, we sold 15,000,000 common units from which we received net proceeds of $307 million, including our General Partner's proportionate net capital contribution of $6 million. We used the proceeds from our May 2004 public offering to completely repay the $225 million Interim Term Loan and to temporarily reduce debt outstanding under our revolving credit facilities.

Our debt obligations

Our debt consisted of the following at the dates indicated:

	March 31, 2004	December 31, 2003
Borrowings under:		
Interim Term Loan, variable rate, repaid in May 2004 (1)	$ 225,000	$ 225,000
364-Day Revolving Credit Facility, variable rate, due October 2004, $230 million borrowing capacity	90,000	70,000
Multi-Year Revolving Credit Facility, variable rate, due November 2005, $270 million borrowing capacity (2)	160,000	115,000
Senior Notes A, 8.25% fixed rate, due March 2005	350,000	350,000
Seminole Notes, 6.67% fixed rate, $15 million due in December 2004 and 2005 (3)	30,000	30,000
MBFC Loan, 8.70% fixed rate, due March 2010	54,000	54,000
Senior Notes B, 7.50% fixed rate, due February 2011	450,000	450,000
Senior Notes C, 6.375% fixed rate, due February 2013	350,000	350,000
Senior Notes D, 6.875% fixed rate, due March 2033	500,000	500,000
Total principal amount	2,209,000	2,144,000
Unamortized balance of increase in fair value related to hedging a portion of fixed-rate debt	7,828	1,531
Less unamortized discount on Senior Notes A, B, and D	(5,952)	(5,983)
Subtotal long-term debt	2,210,876	2,139,548
Less current maturities of debt (4)	(15,000)	(240,000)
Long-term debt (4)	$ 2,195,876	$ 1,899,548
Standby letters of credit outstanding, $75 million of credit capacity available under our Multi-Year Revolving Credit Facility	$ 1,300	$ 1,300

(1) We used the proceeds from our May 2004 common unit offering to fully repay the Interim Term Loan.
(2) This revolving credit facility has $270 million of total borrowing capacity, which is reduced by the amount of standby letters of credit outstanding.
(3) Solely as to the assets of our subsidiary, Seminole Pipeline Company, our $2.2 billion in senior indebtedness at March 31, 2004 is structurally subordinated and ranks junior in right of payment to the $30 million of indebtedness of Seminole Pipeline Company.
(4) In accordance with SFAS No. 6, "Classification of Short-Term Obligations Expected to Be Refinanced," long-term and current maturities of debt at March 31, 2004 reflect the classification of such debt obligations at May 5, 2004. With respect to our 364-Day Revolving Credit Facility, borrowings under this facility are not included in current maturities because we have the option and ability to convert any revolving credit balance outstanding at maturity to a one-year term loan (due October 2005) in accordance with the terms of the agreement. With respect to our Interim Term Loan, we reclassified this amount to long-term debt at March 31, 2004 since we used the proceeds from our May 2004 equity offering to repay this obligation.

Scheduled future maturities of long-term debt. We have long and short-term payment obligations under credit agreements such as our Senior Notes and revolving credit facilities. Scheduled future maturities of debt at March 31, 2004 were: $240 million due in 2004; $615 million due in 2005; $54 million due in 2010; $450 million due in 2011; $350 million due in 2013; and $500 million due in 2033. On May 5, 2004, we used $307 million in net proceeds fromour May 2004 equity offering to repay the $225 million Interim Term Loan and approximately $80 million to temporarily reduce debt outstanding under our revolving credit facilities.

Parent-Subsidiary guarantor relationships. We act as guarantor of the debt obligations of our Operating Partnership, with the exception of the Seminole Notes. If the Operating Partnership were to default on any debt we guarantee, we would be responsible for full repayment of that obligation. The Seminole Notes are unsecured obligations of Seminole Pipeline Company (of which we own an effective 78.4% of its capital stock).

Covenants. We were in compliance with the various covenants of our debt agreements at March 31, 2004 and December 31, 2003.

Information regarding variable interest rates paid

The following table shows the range of interest rates paid and weighted-average interest rate paid on our variable rate debt obligations for the three months ended March 31, 2004:

	Range of interest rates paid	**Weighted-average interest rate paid**
364-Day Revolving Credit Facility	1.17% - 4.00%	1.82%
Multi-Year Revolving Credit Facility	1.67% - 4.00%	1.71%
Interim Term Loan	1.72% - 1.78%	1.76%

Credit ratings

Our current senior unsecured credit ratings are Baa2 as rated by Moody's Investor Services and BBB- as rated by Standard and Poor's, both are investment grade. In December 2003, as a result of our execution of definitive agreements with GulfTerra and El Paso to merge with GulfTerra, Moody's put our rating under review for possible downgrade and Standard and Poor's placed our rating on credit watch with negative implications. Both debt rating agencies will be reviewing the credit attributes and the risk profile of the merged partnership as well as the execution risk of the permanent financing of the proposed merger.

We believe that the maintenance of an investment grade credit rating is important in managing our liquidity and capital resource requirements. We maintain regular communications with these ratings agencies, each of which independently judges our creditworthiness based on a variety of quantitative and qualitative factors.

Our material contractual obligations

With regards to our material contractual obligations, there have been no significant changes outside of the ordinary course of business since December 31, 2003 with the exception that we used net proceeds from our May 2004 equity offering to repay the $225 million Interim Term Loan and approximately $80 million to temporarily reduce debt outstanding under our revolving credit facilities.

Capital spending

For the three months ended March 31, 2004 and 2003, we spent $15 million and $23.8 million on capital projects recorded as property, plant and equipment. The following table summarizes our capital expenditures for the periods indicated:

	For the Three Months Ended March 31,	
	2004	2003
Capital expenditures by segment:		
Pipelines	$ 7.1	$ 8.7
Fractionation	3.6	5.0
Processing	3.4	15.2
Octane Enhancement	2.0	
Other	5.1	3.4
Reclassifications (1)	(6.2)	(8.5)
Total capital expenditures	$ 15.0	$ 23.8
Sustaining capital expenditures (2)	$ 4.2	$ 2.3
Expansion capital expenditures (2)	10.8	21.5
Total capital expenditures	$ 15.0	$ 23.8

(1) Represents the reversal of prior year-end construction-in-progress accruals, which is offset by the recording of actual amounts during the current year in the capital expenditure by segment totals.

(2) For internal reporting purposes, we generally classify improvements and major renewals of existing assets as sustaining capital expenditures and all other capital spending (on existing and new assets) as expansion capital expenditures.

For the remainder of 2004, we expect our share of capital expenditures to approximate $62 million, of which $29 million is forecast to be spent on Pipelines segment projects and approximately $19 million on modifications to the BEF facility to produce iso-octane. We expect to invest approximately $7 million in the capital projects of our unconsolidated affiliates during the remainder of 2004, of which $5.9 million is attributable to projects of our Gulf of Mexico natural gas pipeline investments. At March 31, 2004, we had approximately $3 million in outstanding purchase commitments related to capital projects.

Retained Leases

In 1998, EPCO assigned to us the purchase options associated with certain operating leases that it contributed to us at our formation (the "retained leases"). We have notified the lessor of an isomerization unit covered under the retained leases of our intent to exercise the purchase option relating to this equipment in 2004. Under the terms of the lease agreement for the isomerization unit, we have the option to purchase the equipment at the lesser of fair value or $23.1 million. Should we decide to exercise all of the remaining purchase options associated with the retained leases (which are also at fair value), up to an additional $2.8 million would be payable in 2004, $2.3 million in 2008 and $3.1 million in 2016. These cash outlays would be in addition to the $68 million in forecasted capital project spending for 2004 as discussed in the previous paragraph.

Pipeline Integrity Costs

Our NGL, petrochemical and natural gas pipelines are subject to pipeline safety programs administered by the U.S. Department of Transportation, through its Office of Pipeline Safety. This federal agency has issued safety regulations containing requirements for the development of integrity management programs for hazardous liquid pipelines (which include NGL and petrochemical pipelines) and natural gas pipelines. In general, these regulations require companies to assess the condition of their pipelines in certain high consequence areas (as defined by the regulation) and to perform any necessary repairs. In connection with the new regulations for hazardous liquid pipelines, we developed a pipeline integrity management program in 2002. We are currently preparing an integrity management program for our natural gas pipelines, which must be completed by December 2004.

During the first three months of 2004, we spent approximately $1.9 million to comply with these new regulations, of which $1.2 million was recorded as an operating expense of our Pipelines segment. Based on information currently available, our cash outlays for this program are estimated at $15.5 million for the remainder of 2004 and in the range of $9 million to $19 million for each of the years 2005 through 2008. At present, we expect that approximately 90% of our pipeline integrity management program costs will be recorded as operating expenses within our Pipelines segment. The remainder will be classified as sustaining capital expenditures.

RECENT ACCOUNTING DEVELOPMENTS

FIN 46, "Consolidation of Variable Interest Entities – An Interpretation of ARB No. 51." This interpretation of ARB No. 51 addresses requirements for accounting consolidation of a variable interest entity ("VIE") with its primary beneficiary. In general, if an equity owner of a VIE meets certain criteria defined within FIN 46, the assets, liabilities and results of the activities of the VIE should be included in the consolidated financial statements of the owner. Our adoption of FIN 46 (as amended by FIN 46R) in 2003 has had no material effect on our consolidated financial statements.

Due to the complexity of FIN 46 (as amended by FIN 46R and interpreted), the FASB is continuing to provide guidance regarding implementation issues. Since this guidance is still continuing, our conclusions regarding the application of this guidance may be altered. As a result, adjustments may be recorded in future periods as we adopt new FASB interpretations of FIN 46.

EITF 03-16, "Accounting for Investments in Limited Liability Companies." This accounting guidance requires that investments in limited liability companies (or "LLCs") that have separate ownership accounts for each investor be accounted for similar to a limited partnership investment under SOP No. 78-9, "*Accounting for Investments in Real Estate Ventures*." Under this new guidance (applicable for the period beginning July 1, 2004), investors would be required to apply the equity method of accounting to their investments at a much lower ownership threshold (typically any ownership interest greater than 3-5%) than the 20% threshold applied under APB Opinion No. 18, "*The Equity Method of Accounting for Investments in Common Stock*."

Currently, we account for our 13.1% investment in Venice Energy Services Company, LLC ("VESCO") using the cost method. As a result, we have recognized dividend income from VESCO to the extent that we have received cash distributions from them. In accordance with the new accounting guidance in EITF 03-16, we will record a retroactive cumulative effect adjustment equal to the difference between (i) equity earnings from VESCO that would have been recorded using the equity method in prior periods and (ii) the dividend income from VESCO that was recorded using the cost method. We are currently studying the effect that EITF 03-16 will have on our investment in VESCO; however, based on information available, we do not believe that the implementation of this new accounting guidance will have a material effect on our financial statements.

OUR CRITICAL ACCOUNTING POLICIES

In our financial reporting process, we employ methods, estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as of the date of our financial statements. These methods, estimates and assumptions also affect the reported amounts of revenues and expenses during the reporting period. Investors should be aware that actual results could differ from these estimates if the underlying assumptions prove to be incorrect.

In general, there have been no significant changes in our critical accounting policies since December 31, 2003. For a detailed discussion of these policies, please read "*Management's Discussion and Analysis of Financial Condition and Results of Operations – Our critical accounting policies*" in our annual report on Form 10-K for 2003. The following information summarizes the estimation risk underlying our most significant financial statement items:

Depreciation methods and estimated useful lives of property, plant and equipment

In general, depreciation is the systematic and rational allocation of an asset's cost, less its residual value (if any), to the periods it benefits. We use the straight-line method to depreciate our property, plant and equipment. Our estimate of an asset's useful life is based on a number of assumptions including technological changes that may affect the asset's usefulness and the manner in which we intend to physically use the asset. If we subsequently change our assumptions regarding these factors, it would result in an increase or decrease in depreciation expense.

At March 31, 2004 and December 31, 2003, the net book value of our property, plant and equipment was $2.9 billion and $3.0 billion, respectively. For additional information regarding our property, plant and equipment, please read Note 5 of the Notes to Unaudited Consolidated Financial Statements included under Item 1 of this quarterly report.

Measuring recoverability of long-lived assets and equity method investments

Long-lived assets (including intangible assets with finite useful lives and property, plant and equipment) are reviewed for impairment whenever events or changes in circumstances indicate that their carrying amount may not be recoverable. Long-lived assets with recorded values that are not expected to be recovered through future expected cash flows are written-down to their estimated fair values. The carrying value of a long-lived asset is not recoverable if it exceeds the sum of undiscounted estimated cash flows expected to result from the use and eventual disposition of the existing asset. Our estimates of such undiscounted cash flows are based on a number of assumptions including anticipated margins and volumes; estimated useful life of the asset or asset group; and salvage values. An impairment charge would be recorded for the excess of the long-lived asset's carrying value and its fair value, which is based on a series of assumptions similar to those used to derive undiscounted cash flows but incorporating probabilities that reflect a range of possible outcomes and market value and replacement cost estimates.

Equity method investments (such as our investments in GulfTerra GP and Promix) are evaluated for impairment whenever events or changes in circumstances indicate that there is a loss in value of the investment which is an other than temporary decline. Examples of such events or changes including continued operating losses of the investee or long-term negative changes in the investee's industry. The carrying value of an equity method investment is not recoverable if it exceeds the sum of discounted estimated cash flows expected to be derived from the investment. This estimate of discounted cash flows is based on a number of assumptions including discount rates; probabilities assigned to different cash flow scenarios; anticipated margins and volumes and estimated useful life of the investment.

Our investment in certain unconsolidated affiliates includes excess cost amounts that have been attributed to goodwill. For GulfTerra GP, the excess cost amount attributed to goodwill at March 31, 2004 and December 31, 2003 is $328.2 million. The goodwill amount (which represents potential intangible assets, excess of fair values over carrying values of tangible assets, and remaining goodwill, if any) for GulfTerra GP represents our preliminary allocation of the purchase price pending completion of a fair value analysis which is expected to be completed during the second half of 2004. To the extent that our preliminary allocation of the excess cost of GulfTerra GP is ultimately attributed to depreciable or amortizable assets, our equity earnings from GulfTerra GP will be reduced from what it otherwise would be. For a table showing the impact of potential reclassification of the GulfTerra GP excess cost amount, please read Note 6 of the Notes to Unaudited Consolidated Financial Statements included under Item 1 of this quarterly report.

For the three months ended March 31, 2004 and 2003, we did not record any impairment charges related to our long-lived assets or equity method investments.

Amortization methods and estimated useful lives of qualifying intangible assets

Our recorded intangible assets primarily consist of the estimated value assigned to certain contract-based assets representing the rights we own arising from contractual agreements. A contract-based intangible asset with a finite useful life is amortized over its estimated useful life. Our estimate of useful life is based on a number of factors including the expected useful life of related assets (i.e., fractionation facility, pipeline, etc.) and the effects of obsolescence, demand, competition and other factors. If our underlying assumptions regarding the useful life of an intangible asset change, we then might need to adjust the amortization period of such asset which would increase or decrease amortization expense. Additionally, if we determine that an intangible asset's unamortized cost may not be recoverable due to impairment, this would result in a charge against earnings.

At March 31, 2004 and December 31, 2003, the carrying value of our intangible asset portfolio was $265.1 million and $268.9 million. For additional information regarding our intangible assets, please read Note 7 of the Notes to Unaudited Consolidated Financial Statements included under Item 1 of this quarterly report.

Methods we employ to measure the fair value of goodwill

Our goodwill is attributable to the excess of the purchase price over the fair value of assets acquired. Goodwill is not amortized. Instead, goodwill is tested for impairment at a reporting unit level annually, and more frequently, if circumstances warrant. This testing involves calculating the fair value of a reporting unit, which in turn is based on our assumptions regarding the future economic prospects of the reporting unit. If the fair value of the reporting unit (including related goodwill) is less than its book value, a charge to earnings would be required to reduce the carrying value of goodwill to its implied fair value. If our underlying assumptions regarding the future economic prospects of a reporting unit change, this could further impact the fair value of the reporting unit and result in an additional charge to earnings to reduce the carrying value of goodwill.

At March 31, 2004 and December 31, 2003, the carrying value of our goodwill was $82.4 million. For additional information regarding our goodwill, please read Note 7 of the Notes to Unaudited Consolidated Financial Statements included under Item 1 of this quarterly report.

Our revenue recognition polices

In general, we recognize revenue from our customers when all of the following criteria are met: (i) firm contracts are in place, (ii) delivery has occurred or services have been rendered, (iii) pricing is fixed and determinable and (iv) collectibility is reasonably assured. When contracts settle (i.e., either physical delivery of product has taken place or the services designated in the contract have been performed), we determine if an allowance is necessary and record it accordingly. Historically, the consolidated revenues we recorded were not materially based on estimates. However, as SEC regulations require us to submit financial information on increasingly accelerated timeframes, our use of estimates will increase. We believe the assumptions underlying any revenue estimates that we might use will not prove to be materially different from actual amounts due to our development and implementation of a fully integrated volume management system that is inclusive of operational activities through financial accounting.

RELATED PARTY TRANSACTIONS

Relationship with EPCO

We have an extensive and ongoing relationship with EPCO. EPCO is controlled by Dan L. Duncan, who is also a director (and Chairman of the Board of Directors) of our General Partner. In addition, the remaining executive and other officers of our General Partner are employees of EPCO, including O.S. Andras who is President and Chief Executive Officer and a director of the General Partner. The principal business activity of the General Partner is to act as our managing partner. Collectively, EPCO and its affiliates owned 56.6% of Enterprise at March 31, 2004, which includes the 2% ownership interest of our General Partner (of which EPCO and its affiliates own 100%).

We have no employees. All of our management, administrative and operating functions are performed by employees of EPCO pursuant to the Administrative Services Agreement. Prior to January 1, 2004, we reimbursed EPCO for the costs of its employees who performed operating functions for us and for costs related to certain of its management and administrative personnel hired in response to the expansion of our business. In addition, we paid EPCO a monthly fee for services provided by its other management and administrative employees. On January 1, 2004, the Administrative Services Agreement was amended to eliminate the fee portion of this reimbursement and to provide that we reimburse EPCO for all costs related to management or administrative support for us.

We also have entered into an agreement with EPCO to provide trucking services to us for the transportation of NGLS and other products. In addition, we also buy from and sell to EPCO's Canadian affiliate certain NGL products.

Relationship with Shell

We have a significant commercial relationship with Shell as a partner, customer and vendor. At March 31, 2004, Shell owned an approximate 18.3% equity interest in Enterprise. Shell is our largest customer. Our revenues from Shell primarily reflect the sale of NGL and petrochemical products to Shell and the fees we charge Shell for natural gas processing, pipeline transportation and NGL fractionation services. Our operating costs and expenses with Shell primarily reflect the payment of energy-related expenses related to the Shell natural gas processing agreement and the purchase of NGL products from Shell.

Relationship with unconsolidated affiliates

Our significant related party transactions with unconsolidated affiliates consist of the sale of natural gas to Evangeline, purchase of pipeline transportation services from Dixie and purchase of NGL storage, transportation and fractionation services from Promix. In addition, we sell natural gas to Promix.

The following table summarizes our related party revenues, operating costs and expenses, and selling, general and administrative costs for the periods indicated:

	For the Three Months Ended March 31,	
	2004	**2003**
Revenues		
EPCO and affiliates	$ 2,143	$ 563
Shell and affiliates	104,100	82,220
Unconsolidated affiliates	49,060	50,021
Operating costs and expenses		
EPCO and affiliates	39,113	46,205
Shell and affiliates	166,830	171,714
Unconsolidated affiliates	9,582	16,483
Selling, general and administrative costs		
EPCO and affiliates	6,894	6,384

OTHER ITEMS

Cumulative effect of change in accounting principle recorded in first quarter of 2004

On January 1, 2004, our majority owned BEF subsidiary changed its method of accounting for planned major maintenance activities from the accrue-in-advance method to the expense-as-incurred method. These major maintenance costs, which typically result in facility shutdowns for 30 to 45 days, are principally comprised of amounts paid to third parties for materials, contract services, and other related items.

We have historically used the expense-as-incurred method for planned major maintenance activities. The change in accounting for our majority owned BEF subsidiary conforms the Company's accounting for all planned major maintenance costs and changes the method to better reflect expenses in the period incurred. As such, we believe the change is to a method that is preferable under the circumstances.

The cumulative effect of this accounting change for years prior to 2004, which is shown separately in the Statement of Consolidated Operations and Comprehensive Income, resulted in a gross benefit of $7 million being recorded on January 1, 2004. After adjusting for the minority interest portion, the net effect on our earnings is $4.7

million. For information regarding the effect of this change on basic and diluted earnings per unit, please read Note 14 of the Notes to Unaudited Consolidated Financial Statements included under Item 1 of this quarterly report.

For the periods indicated, the following table shows pro forma net income, basic earnings per unit and diluted earnings per unit amounts assuming the accounting change was applied retroactively to January 1, 2003:

	For the Three Months Ended March 31,	
	2004	**2003**
Pro Forma income statement amounts:		
Income before minority interest	$ 54,482	$ 41,846
Net income before general partner interest	$ 53,866	$ 39,534
Limited partner interest in net income	$ 46,637	$ 35,406
Pro forma per unit data (basic):		
Units outstanding (see Note 14)	218,463	186,191
Per unit data:		
Income before minority interest	$ 0.25	$ 0.22
Net income before general partner interest	0.25	0.21
Limited partner interest in net income	$ 0.21	$ 0.19
Pro forma per unit data (diluted):		
Units outstanding (see Note 14)	218,960	196,191
Per unit data:		
Income before minority interest	$ 0.25	$ 0.21
Net income before general partner interest	0.25	0.20
Limited partner interest in net income	$ 0.21	$ 0.18

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

We are exposed to financial market risks, including changes in commodity prices and interest rates. We may use financial instruments (i.e., futures, forwards, swaps, options and other financial instruments with similar characteristics) to mitigate the risks of certain identifiable and anticipated transactions. In general, the type of risks we attempt to hedge are those related to the variability of future earnings and cash flows caused by changes in commodity prices and interest rates. As a matter of policy, we do not use financial instruments for speculative (or "trading") purposes.

We recognize our financial instruments on the balance sheet as assets and liabilities based on the instrument's fair value. Fair value is generally defined as the amount at which the financial instrument could be exchanged in a current transaction between willing parties, not in a forced or liquidation sale. The estimated fair values of our financial instruments have been determined using available market information and appropriate valuation techniques. We must use considerable judgment, however, in interpreting market data and developing these estimates. Accordingly, our fair value estimates are not necessarily indicative of the amounts that we could realize upon disposition of these instruments. The use of different market assumptions and/or estimation techniques could have a material effect on our estimates of fair value.

Changes in the fair value of financial instrument contracts are recognized currently in earnings unless specific hedge accounting criteria are met. If the financial instruments meet those criteria, the instrument's gains and losses offset the related results of the hedged item in the Statement of Operations and Comprehensive Income for a fair value hedge and are deferred in other comprehensive income for a cash flow hedge. Gains and losses on a cash flow hedge are reclassified into earnings when the forecasted transaction affects earnings. A contract designated as a hedge of an anticipated transaction that is no longer likely to occur is immediately recognized in earnings.

To qualify as a hedge, the item to be hedged must expose us to commodity or interest rate risk and the hedging instrument must reduce the exposure and meet the hedging requirements of SFAS No. 133, "*Accounting for Derivative Instruments and Hedging Activities*" (as amended and interpreted). We must formally designate the financial instrument as a hedge and document and assess the effectiveness of the hedge at inception and on a quarterly basis. Any ineffectiveness is recorded into earnings immediately.

Due to the complexity of SFAS No. 133 (as amended and interpreted), the FASB is continuing to provide guidance about implementation issues. Since this guidance is still continuing, our conclusions regarding the application of guidance may be altered. As a result, adjustments may be recorded in future periods as we adopt new FASB interpretations of this guidance. For additional information regarding our financial instruments, please read Note 12 of the Notes to Unaudited Consolidated Financial Statements included under Item 1 of this quarterly report.

Interest rate risk hedging program

Our interest rate exposure results from variable and fixed rate borrowings under debt agreements. We assess the cash flow risk related to interest rates by identifying and measuring changes in our interest rate exposures that may impact future cash flows and evaluating hedging opportunities to manage these risks. We use analytical techniques to measure our exposure to fluctuations in interest rates, including cash flow sensitivity analysis to estimate the expected impact of changes in interest rates on our future cash flows. The General Partner oversees the strategies associated with these financial risks and approves instruments that are appropriate for our requirements.

We manage a portion of our interest rate risks by utilizing interest rate swaps and similar arrangements. The objective of entering into this type of arrangement is to manage debt service costs by converting a portion of fixed rate debt into variable rate debt or a portion of variable rate debt into fixed rate debt. In general, an interest rate swap requires one party to pay a fixed interest rate on a defined (or "notional") amount while the other party pays a variable rate based on the same notional amount. The notional amount specified in an interest rate swap agreement does not represent exposure to credit loss. We monitor our positions and the credit ratings of counterparties. Management believes the risk of incurring a credit loss on these financial instruments is remote, and that if incurred, such losses would be minimal. We believe that it is prudent to maintain an appropriate balance of variable rate and fixed rate debt.

Fair value hedges – Interest rate swaps. On January 8, 2004, we entered into three interest rate swap agreements under which we exchanged the payment of fixed rate interest on a portion of principal outstanding under Senior Notes B and C for variable rate interest:

Hedged Fixed Rate Debt	Period Covered by Swap	Termination Date of Swap	Fixed to Variable Rate	Notional Amount
Senior Notes B, 7.50% fixed rate, due Feb. 2011	Jan. 2004 to Feb. 2011	Feb. 2011	7.50% to 4.6%	$50 million
Senior Notes C, 6.375% fixed rate, due Feb. 2013	Jan. 2004 to Feb. 2013	Feb. 2013	6.375% to 3.1%	$100 million
Senior Notes C, 6.375% fixed rate, due Feb. 2013	Jan. 2004 to Feb. 2013	Feb. 2013	6.375% to 3.1%	$100 million

We have designated these interest rate swaps as fair value hedges under SFAS No. 133 since they mitigate changes in the fair value of the underlying fixed rate debt. These agreements have a combined notional amount of $250 million and match the maturity dates of the underlying debt being hedged. Under the swap agreements, we pay the counterparty a variable rate based on LIBOR (plus an applicable margin) and receive back from the counterparty a fixed rate payment equal to the stated interest rate of the debt being hedged, based on the notional amounts for each swap agreement. We settle amounts receivable from or payable to the counterparties every six months (the "settlement period").

As effective fair value hedges, an increase in the fair value of these interest rate swaps is equally offset by a increase in fair value of the underlying hedged debt. The offsetting changes in fair value have no effect on current period interest expense. However, the interest rate swaps effectively converted a portion of the underlying fixed rate debt (i.e., the notional amounts hedged for Senior Notes B and C) into variable rate debt. As a result, interest expense will vary depending on the variable rates payable by us under terms of the swap agreements at the end of each settlement period. To the extent that the variable rate amount payable by us at the end of each settlement period is less than the fixed rate amount receivable from the counterparty, we will amortize the difference ratably to earnings as a reduction in interest expense over the settlement period. If the variable rate payable by us at the end of each settlement period is more than the fixed rate amount receivable from the counterparty, we would amortize this difference ratably to earnings as an increase in interest expense over the settlement period.

Total fair value of the interest rate swaps at March 31, 2004 was approximately $6.4 million with an offsetting increase in fair value of the underlying debt. Interest expense in our Statement of Consolidated Operations and Comprehensive Income for the three months ended March 31, 2004 reflects a $1.7 million benefit from these swaps.

The following tables shows the effect of hypothetical price movements on the fair value ("FV") of our interest rate swaps and potential change in the fair value of the debt at the dates indicated:

Scenario	**Resulting Classification**	**Swap FV at 03/31/04**	**Change in Fair Value of Debt**
FV assuming no change in underlying interest rates	*Asset (Liability)*	$ 6,357	$ (6,357)
FV assuming 10% increase in underlying interest rates	*Asset (Liability)*	$ (1,772)	$ 8,129
FV assuming 10% decrease in underlying interest rates	*Asset (Liability)*	$ 14,486	$ (8,129)

Scenario	**Resulting Classification**	**Swap FV at 04/22/04**	**Change in Fair Value of Debt**
FV assuming no change in underlying interest rates	*Asset (Liability)*	$ (6,875)	$ 6,875
FV assuming 10% increase in underlying interest rates	*Asset (Liability)*	$ (16,356)	$ 9,481
FV assuming 10% decrease in underlying interest rates	*Asset (Liability)*	$ 2,606	$ (9,481)

The fair value of the interest rate swaps excludes the benefit we have already recorded in earnings. The change in fair value between March 31, 2004 and April 22, 2004 is primarily due to an increase in market interest rates.

Cash flow hedges – Forward starting interest rate swaps. On March 17, 2004, we entered into four forward starting interest rate swap transactions with original maturities of September 30, 2004. A forward starting swap is an agreement that effectively hedges the price on a specific U.S. treasury security for an established period of time. The purpose of these transactions was to effectively hedge the underlying U.S. treasury interest rate associated with our anticipated issuance of debt to refinance the existing debt of GulfTerra after the proposed merger is completed. The forward starting interest rate swaps have been designated as cash flow hedges under SFAS No. 133. The notional amount of the anticipated debt issuances was $2 billion.

On April 23, 2004, we elected to terminate these financial instruments in order to manage and maximize the value of the swaps and to reduce future debt service costs. As a result, we received $104.5 million in cash from the counterparties. This amount will be amortized over the life of the anticipated debt (when issued) as a reduction to interest expense. The following table shows the portfolio of forward starting swaps categorized by the term of the underlying anticipated debt offering:

Term of Anticipated Debt Offering (or Forecasted Transaction)	**Notional Amount of Anticipated Debt covered by Forward Starting Swaps**	**Cash Received upon Settlement of Forward Starting Swaps in April 2004**
5-year debt instrument	$ 500.0	$ 18.7
10-year debt instrument	500.0	26.1
15-year debt instrument	500.0	29.4
30-year debt instrument	500.0	30.3
Total	$ 2,000.0	$ 104.5

The non-cash fair value of the forward starting interest rate swaps at March 31, 2004 was $17.0 million and was recorded as a component of AOCI in our Statement of Consolidated Partners' Equity and as an addition to comprehensive income in our Statement of Consolidated Operations and Comprehensive income for the three months ended March 31, 2004. When the $104.5 million cash settlement is recorded during the second quarter of 2004, it will replace the $17.0 non-cash fair value amount in AOCI and comprehensive income.

Commodity risk hedging program

The prices of natural gas, NGLs, petrochemical products and MTBE are subject to fluctuations in response to changes in supply, market uncertainty and a variety of additional factors that are beyond our control. In order to manage the risks associated with our Processing segment activities, we may enter into various commodity financial instruments. The primary purpose of these risk management activities is to hedge our exposure to price risks associated with natural gas, NGL production and inventories, firm commitments and certain anticipated transactions. The commodity financial instruments we utilize may be settled in cash or with another financial instrument.

We do not hedge our exposure related to MTBE price risks. In addition, we generally do not hedge risks associated with the petrochemical marketing activities that are part of our Fractionation segment. In our Pipelines segment, we utilize a limited number of commodity financial instruments to manage the price Acadian Gas charges or pays certain of its customers for natural gas. Lastly, we do not employ commodity financial instruments in our fee-based marketing business classified under the Other segment.

We have adopted a policy to govern our use of commodity financial instruments to manage the risks of our natural gas and NGL businesses. The objective of this policy is to assist us in achieving our profitability goals while maintaining a portfolio with an acceptable level of risk, defined as remaining within the position limits established by the General Partner. We enter into risk management transactions to manage price risk, basis risk, physical risk or other risks related to our commodity positions on both a short-term (less than 30 days) and long-term basis, not to exceed 24 months. The General Partner oversees our strategies associated with physical and financial risks (such as those mentioned previously), approves specific activities subject to the policy (including authorized products, instruments and markets) and establishes specific guidelines and procedures for implementing and ensuring compliance with the policy.

The fair value of our commodity financial instrument portfolio at May 1, 2004, March 31, 2004 and December 31, 2003 and the results of our commodity hedging activities for the three months ended March 31, 2004 and 2003 were all nominal amounts. During both the first quarter of 2004 and the first quarter of 2003, we utilized a limited number of commodity financial instruments.

ITEM 4. CONTROLS AND PROCEDURES.

Our management, with the participation of the CEO and CFO of our General Partner, have evaluated the effectiveness of our disclosure controls and procedures, including internal controls over financial reporting. Collectively, these disclosure controls and procedures are designed to provide us with a reasonable assurance that the information required to be disclosed in periodic reports filed with the SEC is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. The disclosure controls and procedures are also designed to provide reasonable assurance that such information is accumulated and communicated to our management, including our General Partner's CEO and CFO, as appropriate to allow such persons to make timely decisions regarding required disclosures.

Our management does not expect that our disclosure controls and procedures will prevent all errors and all fraud. The design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Based on the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple errors or mistakes. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the controls. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events. Therefore, a control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Our disclosure controls and procedures are designed to provide such reasonable assurances of achieving our desired control objectives, and our CEO and CFO have concluded that our disclosure controls and procedures are effective in achieving that level of reasonable assurance.

Based on their evaluation, the CEO and CFO of our General Partner have concluded that our disclosure controls and procedures are effective to ensure that material information relating to our partnership is made known to management on a timely basis. The CEO and CFO noted no significant deficiencies or material weaknesses in the design or operation of our internal controls over financial reporting that are likely to adversely affect our ability to record, process, summarize and report financial information. Also, they detected no fraud involving management or employees who have a significant role in our internal controls over financial reporting. There have been no significant changes in our internal controls over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) or in other factors that occurred during our last fiscal quarter that have materially affected or are reasonably likely to materially affect our internal controls over financial reporting.

The certifications of our General Partner's CEO and CFO required under Sections 302 and 906 of the Sarbanes-Oxley Act of 2002 have been included as exhibits to this quarterly report on Form 10-Q.

PART II. OTHER INFORMATION.

ITEM 2. CHANGES IN SECURITIES, USE OF PROCEEDS AND ISSUER PURCHASES OF EQUITY SECURITIES.

We did not repurchase any of our common units or Class B special units during the three month period ended March 31, 2004. As of March 31, 2004, we and our affiliates are authorized to repurchase up to 618,400 common units under the December 1998 common unit repurchase program. Any common units repurchased under this publicly announced program are classified as treasury units.

ITEM 6. EXHIBITS AND REPORTS ON FORM 8-K.

(a) Exhibits

Exhibit No.	Exhibit*
2.1	Amendment No. 1 to Parent Company Agreement, dated as of April 19, 2004, by and among Enterprise Products Partners L.P., Enterprise Products GP, LLC, Enterprise Products GTM, LLC, El Paso Corporation, Sabine River Investors I, L.L.C., Sabine River Investors II, L.L.C., El Paso EPN Investments, L.L.C. and GulfTerra GP Holding Company (including the forms of Second Amended and Restated Limited Liability Company Agreement of Enterprise Products GP, LLC, Exchange and Registration Rights Agreement and Performance Guaranty, to be entered into by the parties named therein in connection with the merger of Enterprise and GulfTerra, attached as Exhibits 1, 2 and 3, respectively, thereto) (incorporated by reference to Exhibit 2.1 to the Form 8-K filed April 21, 2004).
3.1	First Amended and Restated Limited Liability Company Agreement of Enterprise Products GP, LLC dated as of September 17, 1999 (incorporated by reference to Exhibit 99.8 to the Form 8-K/A-l filed October 27, 1999).
3.2	Amendment No. 1 to the First Amended and Restated Limited Liability Company Agreement of Enterprise Products GP, LLC dated as of September 19, 2002 (incorporated by reference to Exhibit 3.2 to Form 10-K filed March 31, 2003).
3.3#	Amended and Restated Agreement of Limited Partnership of Enterprise Products Operating L.P. dated as of July 31, 1998 (restated to include all agreements through December 10, 2003).
3.4	Reorganization Agreement, dated as of December 10, 2003, among Enterprise Products Partners, L.P., Enterprise Products Operating L.P., Enterprise Products GP, LLC and Enterprise Products OLPGP, Inc. (incorporated by reference to Exhibit 3.1 to Form 8-K filed December 10, 2003).

3.5	Third Amended and Restated Agreement of Limited Partnership of Enterprise Products Partners L.P. dated May 15, 2002 (restated to include all amendments through December 17, 2003) (incorporated by reference to Exhibit 3.1 to Form 8-K filed February 10, 2004).
4.1	Indenture dated as of March 15, 2000, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and First Union National Bank, as Trustee (incorporated by reference to Exhibit 4.1 to Form 8-K filed March 10, 2000).
4.2	First Supplemental Indenture dated as of January 22, 2003, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.2 to Registration Statement on Form S-4, Reg. No. 333-102776, filed January 28, 2003).
4.3	Global Note representing $350 million principal amount of 6.375% Series A Senior Notes due 2013 with attached Guarantee (incorporated by reference to Exhibit 4.3 to Registration Statement on Form S-4, Reg. No. 333-102776, filed January 28, 2003).
4.4	Global Note representing $350 million principal amount of 6.375% Series B Senior Notes due 2013 with attached Guarantee (incorporated by reference to Exhibit 4.4 to Registration Statement on Form S-4, Reg. No. 333-102776, filed January 28, 2003).
4.5	Registration Rights Agreement dated as of January 22, 2003, among Enterprise Products Operating L.P., Enterprise Products Partners L.P. and the Initial Purchasers named therein (incorporated by reference to Exhibit 4.5 to Registration Statement on Form S-4, Reg. No. 333-102776, filed January 28, 2003).
4.6	Second Supplemental Indenture dated as of February 14, 2003, among Enterprise Products Operating L.P., as Issuer, Enterprise Products Partners L.P., as Guarantor, and Wachovia Bank, National Association, as Trustee (incorporated by reference to Exhibit 4.3 to Form 10-K filed March 31, 2003).
4.7	Rule 144 A Global Note representing $499.2 million principal amount of 6.875% Series A Senior Notes due 2033 with attached Guarantee (incorporated by reference to Exhibit 4.5 to Form 10-K filed March 31, 2003).
4.8	Regulation S Global Note representing $800,000 principal amount of 6.875% Series A Senior Notes due 2033 with attached Guarantee (incorporated by reference to Exhibit 4.6 to Form 10-K filed March 31, 2003).
4.9	Global Note representing $500 million principal amount of 6.875% Series B Senior Notes due 2033 with attached Guarantee (incorporated by reference to Exhibit 4.8 to Form 10-K filed March 31, 2003).
4.10	Registration Rights Agreement dated as of February 14, 2003, among Enterprise Products Operating L.P., Enterprise Products Partners L.P. and the Initial Purchasers named therein (incorporated by reference to Exhibit 4.10 to Form 10-K filed March 31, 2003).
4.11	Global Note representing $350 million principal amount of 8.25% Senior Notes due 2005 (incorporated by reference to Exhibit 4.2 to Form 8-K filed March 10, 2000).
4.12	Global Notes representing $450 million principal amount of 7.50% Senior Notes due 2011 (incorporated by reference to Exhibit 4.1 to Form 8-K filed January 25, 2001).
4.13	Form of Common Unit certificate (incorporated by reference to Exhibit 4.1 to Registration Statement on Form S-1/A; File No. 333-52537, filed July 21, 1998).
4.14	$250 Million Multi-Year Revolving Credit Facility dated as of November 17, 2000, among Enterprise Products Operating L.P., First Union National Bank, as Administrative Agent, Bank One, NA, as Documentation Agent, the Chase Manhattan Bank, as Syndication Agent, and the several banks from time to time parties thereto, with First Union Securities, Inc. and Chase Securities Inc. as Joint Lead Arrangers and Joint Book Managers (incorporated by reference to Exhibit 4.2 to Form 8-K filed January 24, 2001).
4.15	Guaranty Agreement dated as of November 17, 2000, by Enterprise Products Partners L.P. in favor of First Union National Bank, as Administrative Agent, with respect to the $250 Million Multi-Year Revolving Credit Facility included as Exhibit 4.4 above (incorporated by reference to Exhibit 4.4 to Form 8-K filed January 24, 2001).
4.16	First Amendment to Multi-Year Credit Facility dated April 19, 2001 (incorporated by reference to Exhibit 4.12 to Form 10-Q filed May 14, 2001).
4.17	Second Amendment to Multi-Year Revolving Credit Facility dated April 14, 2002 (incorporated by reference to Exhibit 4.14 to Form 10-Q filed May 14, 2002).

4.18	Third Amendment to Multi-Year Revolving Credit Facility dated July 31, 2002 (incorporated by reference to Exhibit 4.1 to Form 10-Q filed August 12, 2002).
4.19	Contribution Agreement dated September 17, 1999 (incorporated by reference to Exhibit "B" to Schedule 13D filed September 27, 1999 by Tejas Energy, LLC).
4.20	Registration Rights Agreement dated September 17, 1999 (incorporated by reference to Exhibit "E" to Schedule 13D filed September 27, 1999 by Tejas Energy, LLC).
4.21	Unitholder Rights Agreement dated September 17, 1999 (incorporated by reference to Exhibit "C" to Schedule 13D filed September 27, 1999 by Tejas Energy, LLC).
4.22	Amendment No. 1, dated September 12, 2003, to Unitholder Rights Agreement dated September 17, 1999 (incorporated by reference to Exhibit 4.1 to Form 8-K filed September 15, 2003).
4.23	364-Day Revolving Credit Agreement dated as of October 30, 2003, among Enterprise Products Operating L.P., Wachovia Bank, National Association, as Administrative Agent, Bank One, N.A., as Syndication Agent, Royal Bank of Canada, The Bank of Nova Scotia and SunTrust Bank, as Co-Documentation Agents, and the several lenders from time to time parties thereto, with Wachovia Capital Markets, LLC and Banc One Capital Markets, Inc., as Joint Lead Arrangers, and Wachovia Capital Markets, LLC, as Sole Manager (incorporated by reference to Exhibit 4.29 to Form 10-Q filed November 13, 2003).
4.24	Guaranty Agreement dated as of October 30, 2003 by Enterprise Products Partners L.P. in favor of Wachovia Bank, National Association, as Administrative Agent, with respect to 364-Day Revolving Credit Facility (incorporated by reference to Exhibit 4.30 to Form 10-Q filed November 13, 2003).
4.25	Fourth Amendment to Multi-Year Revolving Credit Facility dated October 30, 2003 (incorporated by reference to Exhibit 4.31 to Form 10-Q filed November 13, 2003).
4.26	Voting Agreement and Proxy, dated as of December 15, 2003, by and among GulfTerra Energy Partners, L.P., Enterprise Products Delaware Holdings, L.P., the Duncan Family 2000 Trust and Dan L. Duncan (incorporated by reference to Exhibit 4.1 to Schedule 13D, Amendment No. 2, filed December 18, 2003).
4.27	Interim Term Loan Agreement dated December 12, 2003, among Enterprise Products Operating L.P., Lehman Commercial Paper Inc., as Administrative Agent, Bank One NA, The Bank of Nova Scotia, SunTrust Bank and Wachovia Bank, National Association, as Co-Syndicating Agents, and the several banks from time to time parties thereto. (incorporated by reference to Exhibit 4.1 to Form 8-K filed February 10, 2004).
4.28	Guaranty Agreement dated as of December 12, 2003, by Enterprise Products Partners L.P. in favor of Lehman Commercial Paper Inc., as Administrative Agent, with respect to Interim Term Loan Agreement. (incorporated by reference to Exhibit 4.2 to Form 8-K filed February 10, 2004).
4.29	First Amendment to 364-Day Revolving Credit Facility dated December 22, 2003, among Enterprise Products Operating L.P., Wachovia Bank, National Association, as Administrative Agent, and the several lenders from time to time party thereto. (incorporated by reference to Exhibit 4.3 to Form 8-K filed February 10, 2004).
4.30	Fifth Amendment and Supplement to Multi-Year Revolving Credit Facility dated December 22, 2003, among Enterprise Products Operating L.P., Wachovia Bank, National Association, as Administrative Agent, and the several lenders from time to time party thereto. (incorporated by reference to Exhibit 4.4 to Form 8-K filed February 10, 2004).
4.31	$1.2 Billion 364-Day Term Credit Facility dated as of July 31, 2002, among Enterprise Products Operating Partnership L.P., Wachovia Bank, National Association, as Administrative Agent, Lehman Commercial Paper Inc., as Co-Syndication Agent, Royal Bank of Canada, as Co-Syndication Agent and Arranger, with Wachovia Securities, Inc. and Lehman Brothers Inc., as Lead Arrangers and Joint Bookrunners and RBC Capital Markets, as Arranger (incorporated by reference to Exhibit 4.3 to Form 8-K filed August 12, 2002).
4.32	Guaranty Agreement dated as of July 31, 2002 by Enterprise Products Partners L.P. in favor of Wachovia Bank, National Association, as Administrative Agent, with respect to the $1.2 Billion 364-Day Term Credit Facility (incorporated by reference to Exhibit 4.4 to Form 8-K filed August 12, 2002).
10.1	Seventh Amendment to Conveyance of Gas Processing Rights, dated as of April 1, 2004 among Enterprise Gas Processing, LLC, Shell Oil Company, Shell Exploration & Production Company, Shell Offshore Inc., Shell Consolidated Energy Resources Inc., Shell Land & Energy Company,

	Shell Frontier Oil & Gas Inc. and Shell Gulf of Mexico Inc. (incorporated by reference to Exhibit 10.1 to Form 8-K filed April 26, 2004).
18.1#	Letter regarding Change in Accounting Principles dated May 4, 2004.
31.1#	Sarbanes-Oxley Section 302 certification of O.S. Andras for Enterprise Products Partners L.P. for the March 31, 2004 quarterly report on Form 10-Q.
31.2#	Sarbanes-Oxley Section 302 certification of Michael A. Creel for Enterprise Products Partners L.P. for the March 31, 2004 quarterly report on Form 10-Q.
32.1#	Sarbanes-Oxley Section 1350 certification of O.S. Andras for the March 31, 2004 quarterly report on Form 10-Q.
32.2#	Sarbanes-Oxley Section 1350 certification of Michael A. Creel for the March 31, 2004 quarterly report on Form 10-Q.

* With respect to any exhibits incorporated by reference to any Exchange Act filings, the Commission file number for Enterprise Products Partners L.P. is 1-14323.

\# Filed with this report.

(b) Reports on Form 8-K.

January 6, 2004 filing, Items 5 and 7. On January 6, 2004, we filed as an exhibit the unaudited balance sheet of our General Partner dated September 30, 2003.

February 3, 2004, Items 7 and 12. On February 3, 2004, we issued a press release regarding our financial results for the three and twelve-month periods ended December 31, 2003 and 2002. A copy of the earnings press release and related financial information was filed as an exhibit.

February 10, 2004, Items 5 and 7. On February 10, 2004, we filed updates to our partnership agreement and common unit description, various credit facilities and the administrative services agreement with EPCO. Our Third Amended and Restated Agreement of Limited Partnership, Interim Term Loan Agreement and related Guaranty Agreement, First Amendment to 364-Day Revolving Credit Facility, Fifth Amendment and Supplement to Multi-Year Revolving Credit Facility and the Amended and Restated Administrative Services Agreement were attached as exhibits thereto.

March 22, 2004 filing, Items 5 and 7. On March 22, 2004, we filed as an exhibit the audited balance sheet of our General Partner dated December 31, 2003.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this quarterly report on Form 10-Q to be signed on its behalf by the undersigned thereunto duly authorized, in the City of Houston, State of Texas on May 10, 2004.

ENTERPRISE PRODUCTS PARTNERS L.P.
(A Delaware Limited Partnership)

By: Enterprise Products GP, LLC,
as General Partner

By: __ /s/ Michael J. Knesek________________
Name: Michael J. Knesek
Title: Vice President, Controller and Principal Accounting Officer of the General Partner